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PJM's Perspective on Challenges and Potential Solutions for Long-Term Reserve Certainty Reforms

Market Design

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Executive Summary

PJM's reserve needs are evolving. PJM's existing reserves markets primarily address risk associated with large unit loss (i.e., contingency risk). Contingency risk is relatively static, based on what resources are committed to the system. In general, the reserve requirements dictated by the largest contingency are the same or nearly the same in the day ahead and in real time. While PJM will always need to carry reserves to manage contingency risk, this will no longer be sufficient as the energy transition progresses. PJM will need to rely on new operating reserve paradigms, driven by more dynamic uncertainties. In 2023, PJM's hour-ahead net-load forecast error exceeded its largest contingency in more than 130 hours. As more weather-driven renewables come online, there will likely be a time when PJM's net-load forecast uncertainty will be larger than its largest single contingency in most hours – and will far exceed that reserve need in the highest-risk hours.

The time to address these issues is now, while the risks are still emerging. These reforms will take time to design and implement, and if they are not in place before operational issues arise, it will not only create reliability risk but could drive up costs considerably. Changes to PJM's markets are needed to attract and maintain required flexibility services and to shape the generation fleet of the future. If this does not happen, it may lead to significantly more price volatility without a timely recourse to bring needed flexibility online.

PJM's reserve market design must be able to accommodate the dynamic and probabilistic nature of these fundamentally different drivers. As the energy transition progresses, reserve needs will be subject to expected weather and other system conditions and will change as the time of delivery approaches. In general, forecast uncertainty 24 hours ahead of a target time is much larger than 10 minutes ahead.

To be effective, PJM's markets will need to:

- **Effectively evaluate trade-offs between reliability risk and cost.**
- **Recognize operational risk and align market solutions to support operator actions.**
- **Manage changing levels of uncertainty and flexibility needs.**
- **Pre-position the system to ensure future reliability.**

Other RTOs/ISOs are ahead of PJM in these areas and are already responding to these developing demands. Most of PJM's counterparts in other regions have undertaken or are in the process of undertaking major reserve market reforms to navigate the generation fleet's evolution.

Figure 1. Reserve Market Reforms Undertaken Across ISOs/RTOs

	Uncertainty Reserves	Forecasted Ramping Reserves	Multi-Interval Dispatch*	Day-Ahead Specific Products	Reserve Offers > $0
PJM					✓
MISO	✓	✓			✓
CAISO	✓		✓	✓	✓
ISO-NE				✓	✓
NYISO	✓		✓		✓
SPP	✓	✓			✓
ERCOT	✓	✓			✓

**Note: ISOs currently using multi-interval dispatch do not settle any of the intervals beyond the first.*

After conducting a comprehensive literature review, performing outreach to the other ISOs/RTOs, and performing preliminary analysis of PJM's operational data and posture, PJM has identified several key areas of focus as it contemplates reserve market reforms.

1 | PJM's market design must align with operational needs and actions. Operational actions that are consistently and predictably required to maintain system reliability should be reflected in PJM markets to promote transparency, to attract and maintain essential reliability services, and to drive toward least-cost solutions. When PJM operators are routinely required to take out-of-market actions for reliability reasons, this often points to the need for market reforms. Today, PJM dispatchers are sometimes required to commit resources day ahead and out of market to ensure they are available in real time to provide necessary reserve services. This is driven by various operational risks that are not currently reflected in PJM's markets, including forecast errors, lack of fuel security, the gap between the day-ahead load forecast and cleared physical generation, the modeling of network constraints, extreme weather, and generator forced outage risk. Additionally, new operational risks, such as renewable forecast error and more frequent extreme weather events, are emerging. If PJM's markets do not evolve in time to address them, more out-of-market actions will be required, and PJM's competitive markets will fail to send the necessary and appropriate incentive signals.

2 | Accurately valuing reliability services is critical. Under Reserve Price Formation, PJM proposed a holistic redesign of PJM's reserve markets, including updates to its Operating Reserve Demand Curves (ORDCs). Although the full set of reforms was initially approved by FERC, the changes to the ORDCs were later remanded, leaving PJM to implement an incomplete market design. PJM's current ORDC penalty factors are based on lost opportunity cost (LOC) information from an event in August 2007 and do not accurately reflect current operational reality. To provide clear and accurate market signals, PJM's ORDCs should be set at a level to capture economic, available operating reserves, and reserve penalty costs should be consistent with the operational costs and actions that would be taken to mitigate any shortage. If PJM markets fail to accurately represent the value of these flexibility services, PJM will not be able to attract and maintain them, jeopardizing PJM's reliability.

3 | Avoidable costs for providing reserve services should be recoverable through reserve markets. The cost of advanced fuel arrangements and other availability measures to provide reserve services may be unrecoverable through PJM's existing market constructs. Resources are required to offer reserves into PJM's markets even if their cost to provide these services exceeds the allowable offer caps, which today is $0/MWh or very close to $0/MWh. A failure to recognize these costs leads to a misalignment in incentives between the profit-maximizing behavior for resources and what is required for system reliability. This issue must be resolved, both in PJM's existing reserve products and any new products developed moving forward.

PJM proposes to prioritize a set of reforms that include both enhancements to PJM's existing reserve market structures and the development of new products. These reforms are summarized in **Table 1**.

Table 1. Reserve Reforms To Explore

Enhancements to Existing Reserve Markets

Updates to PJM's ORDCs

- Bring availability cost data up to date and better reflect operational actions and costs.
- Develop a coherent energy and ancillary service market design that values each reserve service in the context of both its reliability benefit within the broader suite of services and the value of lost load.

Changes to reserve offer rules

- Quantify potential costs to resources to maintain availability to provide reserve services.
- Update offer structures to ensure that avoidable costs for providing reserves are recoverable through PJM's reserve markets.

Enhancements to performance evaluation and consequences for non-performance

- Update performance evaluation rules for PJM's reserves to better align with how these reserve services are used operationally.
- Update the settlement implications of reserve non-performance to be more reflective of system impact and to ensure alignment with new reserve products moving forward.

Incentives for following PJM dispatch

- Revisit incentives for following PJM dispatch instructions, including deviation charges and compensation for the delivery of unrequested energy.
- Reforms should reflect and support PJM's need to effectively schedule resources to provide reserve services.

New Reserve Products

Day-Ahead Energy Imbalance Reserve

- Develop a product to procure reserves day ahead to bridge the gap between PJM's load forecast and physical generation committed through the Day-Ahead Market.
- Reflect reliability needs into the Day-Ahead Market that are currently being addressed as a part of standard operational practice outside of the market.
- Allow resources to reflect and recover their avoidable costs for providing this service (e.g., fuel arrangement or charging costs).
- Notify resources of the reserve commitment and obligation.
- Develop a market structure to procure reserve services that are needed day ahead but do not need to be carried in real time.

Ramping/Uncertainty Reserves

- Develop a set of products to manage both:
  a) Uncertainty associated with wind, solar, load and interchange forecast error; and
  b) Forecasted ramping needs in future intervals.
- Create a market framework that supports data-driven requirements, which reflect changing operational risk and reliability needs.
- Allow resources to reflect and recover their avoidable costs for providing these services (e.g., fuel arrangement or charging costs).
- Develop market rules to establish clear reserve obligations with appropriate settlement impacts.

Introduction

At the highest level, the objective of the competitive wholesale electricity market is to ensure the reliable delivery of energy at the lowest reasonable cost. PJM has identified several areas that need to be addressed in its reserve markets to better support system reliability, to align PJM's markets with operational reality, and to ensure that PJM is attracting and maintaining critical flexibility services. As PJM considers any new solutions to address existing and emerging challenges, it will be in the context of designing a more efficient, competitive and effective wholesale energy market.

As the energy transition progresses, PJM is facing a new set of challenges. For the first time in years, PJM is projecting significant load growth, driven by new large data centers and electrification. At the same time, generation is retiring due to age and environmental and policy drivers. Today, only a modest portion of PJM's total energy is supplied by renewables. In 2023, renewable energy made up 6.9% of PJM's energy mix, and wind and solar represented 3,367 MW and 3,503 MW of Reliability Pricing Model (RPM)-eligible capacity. However, the share of renewables is expected to grow considerably in coming years. As of Nov. 27, 2024, there were 60,467 MW of solar and 19,156 MW of wind in PJM's interconnection study process. These shifts in the composition of PJM's energy fleet will demand new operational paradigms and market models to ensure that PJM has the flexible capacity it needs to maintain reliability. In considering reserve certainty moving into the future, a few significant themes emerge:

1 | The risk drivers for the grid are changing. Historically, reserve products were primarily designed to manage risk associated with the unexpected loss of a generation resource. As more variable and distributed resources enter the grid, this is no longer sufficient. As additional intermittent, weather-driven resources enter the PJM system, risks associated with forecast error and uncertainty will continue to grow. With the progression of the energy transition, PJM will need to make fundamental changes to how reserve needs are quantified and to how reserve services are valued and settled.

2 | Uncertainty drivers are increasingly dynamic. Many of the operational factors that are driving additional risk and uncertainty change over planning horizons. Unlike the risk associated with the loss of the largest generating resource, which is relatively constant, the operational risks associated with forecast errors that come with the evolving resource mix change over time. As grid operations rely more on information that can never be perfectly forecasted, the telescoping nature of that forecast error must be accounted for as well as the correlation in uncertainty across the performance of weather-driven resources.

3 | The grid of the future will require more probabilistic planning. Currently, PJM markets have a largely deterministic approach to procuring flexibility services. In general, PJM's markets tend to procure services to address a single possible future or scenario, such as the most probable forecasted outcome or the largest single unit loss. This does not always allow for a comprehensive evaluation of the trade-offs between cost and reliability impact. As the drivers creating operational risk become more dynamic and probabilistic in nature, it will become increasingly important that the market is able to weigh the value and cost of procuring additional reliability services given the probability that those impacts will materialize.

4 | Better resource pre-positioning will be needed to provide future flexibility services. With anticipated increases in net-load ramp[1] and more intra-hour uncertainty, market mechanisms are needed to better pre-position the system for upcoming flexibility needs. This may require different or longer look-ahead periods in PJM tools as well as new reserve products.

5 | Existing market structures do not always appropriately value and provide critical reliability services, even in today's grid. PJM has a long history of operating the electrical grid to ensure its continued reliability and security. In some cases, this requires PJM operators to take out-of-market actions. While this meets PJM's core mission of system reliability, repeated and consistent out-of-market actions are often an indicator that the wholesale electricity market does not sufficiently reflect operational needs and value reliability services. This can lead to market inefficiency, the masking of true market costs, and a lack of incentive and investment signals to attract and maintain critical services.

In 2023, PJM presented its stakeholder body with a problem statement outlining a series of near- and long-term concerns that need to be addressed to maintain system reliability, to attract and maintain critical flexibility services, and to better align PJM markets with operational needs, both now and as the energy transition progresses. As a result of the approval of this issue charge, the Reserve Certainty Senior Task Force (RCSTF) was formed.

To date, the RCSTF has advanced three immediate-term packages: one aimed at addressing performance concerns related to the deployment of Synchronized Reserves during Synchronized Reserve Events, a second to better align existing reserve quantities with current operational practice, and a third to allow the Day-Ahead Market to consider

[1] Net-load ramp, as discussed here, represents the ramping behavior (or the megawatt change over time) associated with demand, minus wind and solar generation.

resource hourly notification times when clearing offline reserves.[2] The packages related to deployment of Synchronized Reserves and using hourly notification times in the Day-Ahead Market were endorsed by members. The package aimed at better aligning PJM's reserve requirements with operational practice failed to pass at the Markets and Reliability Committee.

While the two packages that were approved by stakeholders and are currently being implemented will provide incremental benefit, they do not begin to address the broader and significant set of challenges within the approved issue charge. Progress will need to be accelerated moving forward because these bigger reforms will take time to fully design and implement. If they are not in place in time to address reliability issues before they become acute, costs to the system will likely be higher, both in the form of out-of-market payments and in price volatility, as flexibility services become scarce. The purpose of this paper is to outline PJM's initial thinking on the reserve market reforms that will be necessary to navigate the energy transition and to thereby lay the foundation for the RCSTF's work moving forward.

Market Design Principles

PJM has developed a set of guiding principles for market design and effective price formation. These principles will guide PJM's work to reform its ancillary services markets and are set out below.

Price Formation Principles

- Reserve and energy prices reflect system conditions and appropriately value scarcity.
- Operating Reserve Demand Curves (ORDCs) reflect the reliability value of reserves.
- The actual reserve capability on the system is accurately measured.
- Resources assigned reserves will provide them when deployed.
- Market power is mitigated.
- Social welfare is maximized.[3]

Additional Principles Included in PJM's Response to FERC Order AD-21-10, *Modernizing Wholesale Electric Design*[4]

- Proper locational market signals guide optimal investments.
- Solutions are nimble with evolution.
- Market rules are nondiscriminatory.
- Rules encourage robust participation and create efficient market results.
- Simplicity in market design where possible
- Transparency

[2] The Real-Time Market already used (and continues to use) hourly notification times to clear offline reserves.

[3] Maximizing social welfare is the objective function of the market clearing algorithms. The goal of this objective function is to optimally allocate resources for energy and reserves such that the final allocation simultaneously maximizes the benefit to consumers and the revenues to suppliers. This is done by maximizing the difference between the consumer's willingness to pay for a product and the bid production cost of cleared supply.

[4] Modernizing Wholesale Electricity Market Design, Docket No. AD21-10-000 (PDF) Report of PJM Interconnection, L.L.C., Oct. 18, 2022

The Federal Energy Regulatory Commission (FERC) released information on market rules and operational practices, which highlight some areas of concern for energy price formation.[5] The summary published to the FERC website includes the following fundamental concepts, last updated on June 17, 2020, at the time of this report:

- **Use of uplift payments**: Use of uplift payments can undermine the market's ability to send actionable price signals. Sustained patterns of specific resources receiving a large proportion of uplift payments over long periods of time raise additional concerns that those resources are providing a service that should be priced in the market or opened to competition.

- **Offer price mitigation and offer price caps**: All RTOs/ISOs have protocols that endeavor to identify resources with market power and ensure that such resources bid in a manner consistent with their marginal cost. As a backstop to offer price mitigation, RTOs/ISOs also employ offer price caps that are designed to be consistent with scarcity and shortage pricing rules. These protocols require that the RTO/ISO's measure of marginal cost be accurate and allow a resource to fully reflect its marginal cost in its bid. To the extent existing rules on marginal cost bidding do not provide for this, bids and resulting energy and ancillary service prices may be artificially low.

- **Scarcity and shortage pricing**: All RTOs/ISOs have tariff provisions governing operational actions (e.g., dispatching emergency demand response, voltage reductions) to manage operating reserves as they approach a reserve deficiency. These actions often are tied to administrative pricing rules designed to reflect degrees of scarcity in the energy and ancillary services markets. In addition, in the event of an operating reserve shortage, all RTOs/ISOs have adopted separate administrative pricing mechanisms designed to set prices that reflect the economic value of scarcity. To the extent that actions taken to avoid reserve deficiencies are not priced appropriately or not priced in a manner consistent with the prices set during a reserve deficiency, the price signals sent when the system is tight will not incent appropriate short- and long-term actions by resources and load.

- **Operator actions that affect prices**: RTO/ISO operators regularly commit resources that are not economic to address reliability issues or un-modeled system constraints. Some activity may be necessary to maintain system reliability and security. However, to the extent RTOs/ISOs regularly commit excess resources, such actions may artificially suppress energy and ancillary service prices or otherwise interfere with price formation.

These concepts underscore the criticality of ensuring that markets reflect the true cost of operational reliability actions and send the appropriate market signals. If markets fail to serve this core function, investment in the requisite reliability services will not keep up with system needs, jeopardizing long-run reliability.

Enhancements to PJM Tools and Technology

In addition to the market reforms discussed within this paper, PJM also plans to consider how upgrades to its market tools and technologies can support these objectives and help to promote reliability and market efficiency.

[5] Energy Price Formation: Information on Market Rules and Operational Practices, Federal Energy Regulatory Commission, ferc.gov, last updated on June 17, 2020

Intermediate-Term Security Constrained Economic Dispatch (IT SCED)

To complement the broader set of market reforms and in parallel with the RCSTF's efforts, PJM intends to explore enhancements to its Intermediate-Term Security Constrained Economic Dispatch engine (IT SCED). IT SCED is PJM's intraday commitment tool that provides advisory information to dispatchers on resources to call online to serve load in future intervals. Today, IT SCED is solved 30 minutes prior to the target interval to make recommendations and has a two-hour look-ahead horizon beyond that. It uses the distribution factors of the current network topology to evaluate deliverability against constraints. IT SCED runs the Three Pivotal Supplier test and feeds that information into PJM's Real-Time Security Constrained Economic Dispatch (RT SCED) for the purpose of power market mitigation. It also schedules inflexible reserves, makes economic demand response commitment decisions, recommends commitment of Fast-Start Resources and sets the Locational Marginal Price (LMP) at interface points for the purpose of the Coordinated Transaction Scheduling (CTS) process.

As PJM considers new market mechanisms to handle system uncertainty and better pre-position the system for meeting future flexibility needs, enhancements to IT SCED may help support these efforts. PJM anticipates evaluating possible changes, which may include but are not limited to:

- The IT SCED look-ahead time and how intervals are spaced within that window
- The forecast information used
- The distribution factors used to represent system network topology in future intervals

Market Technology Upgrades

PJM is always looking at new technologies for solving its energy and ancillary service markets in a timely manner. PJM is currently focused on the Next Generation Markets (nGEM) optimization engine to improve the performance, scalability, composability, parallelization, extensibility and testability of its market clearing engines. The nGEM optimization engine will enable PJM to implement more accurate resource models that better reflect operational characteristics and limitations, including for pumped storage hydro, steam turbine, combined cycle, energy storage and hybrid resources. These enhancements to resource modeling will give PJM the ability to better quantify available reserve capability and efficiently utilize the various operating modes of combined cycle, steam, energy storage and hybrid resources. Additionally, PJM's Information Technology Services Division evaluates the currently available hardware technology roughly every three years to identify new hardware advances that will work with PJM's market clearing engine software technologies to improve overall solution time of the optimization engines.

New Reserve Products

PJM anticipates the need for two new types of reserve products in the near term. The first is a day-ahead reserve product that accounts for the gap between cleared physical supply in the Day-Ahead Market and forecasted load. These reserves would be procured through the Day-Ahead Market, with the appropriate compensation and binding performance obligation, to ensure that there is sufficient physical supply to meet the forecasted demand. Given that this gap does not exist in real time when the demand forecast materializes, this reserve requirement would not be maintained in real time.

The second category of reserve products are ramping/uncertainty reserve products, which would be used to handle uncertainties associated with net-load forecast error and the expected ramp flexibility needed in future intervals.

These products would be procured both through the Day-Ahead Market and Real-Time Market, though greater quantities may be required day ahead.

Day-Ahead Energy Imbalance Reserve (DA-EIR)

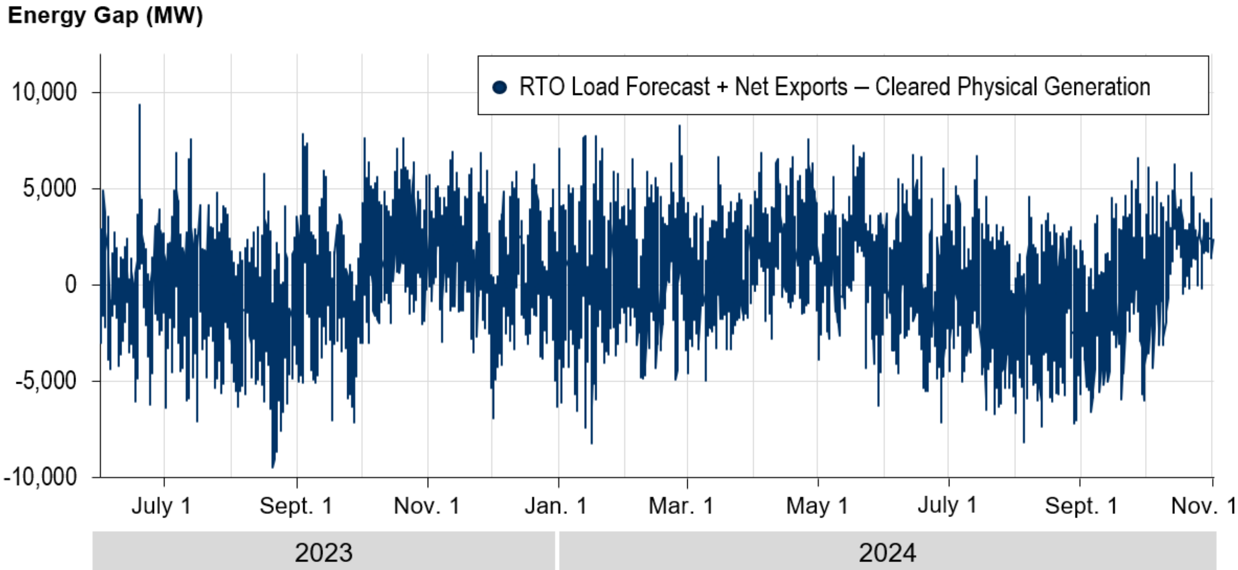
Challenges To Be Addressed

PJM currently clears its Day-Ahead Market to meet the bid-in demand, which may be lower than PJM's load forecast for the next operating day. Cleared virtual supply can further widen the gap between forecasted load and cleared physical generation. When this energy gap is substantial, PJM dispatchers may have to take out-of-market actions to ensure that the physical energy and reserve capability needed to meet forecasted load are available to preserve reliability.

One of the primary ways that PJM does this is with the Reliability Assessment and Commitment (RAC) tool. RAC accounts for the gap between bid-in and forecasted demand. RAC also incorporates any updated information available since the Day-Ahead Market solved, such as updates to the load forecast, unplanned outages and scheduled interchange. RAC takes the Day-Ahead Market commitment, accounting for any changes in resources' availability, and then recommends additional resource commitments as necessary to meet forecasted demand. The fact that these commitments are not included in the Day-Ahead Market optimization can lead to market inefficiency. Additionally, since units committed through the RAC do not receive day-ahead energy or reserves awards, they do not have a Day-Ahead Market position and may not always have sufficient incentive to take any necessary steps to be available to provide those services the next operating day. Such steps may include managing or making supply arrangements, conducting maintenance and staffing facilities.

Figure 2 shows the difference between the day-ahead demand forecast and day-ahead bid-in demand from June 2023 through October 2024.

Figure 2. Gap between the amount of generation needed to meet the load forecast and scheduled net exports and the amount of physical generation cleared by the Day-Ahead Market



Practices in Other ISOs/RTOs

To address the need for additional flexible capacity due to the gap between the amount of physical supply cleared in the Day-Ahead Market and the load forecast, CAISO has implemented two products: "Reliability Capacity Up" and "Reliability Capacity Down." The Reliability Capacity Up product is procured when the demand forecast exceeds the cleared physical energy in the Day-Ahead Market, and the Reliability Capacity Down product is procured when the reverse is true. These capability products bridge the gap between the financial market day ahead and the physical real-time market. They do not address net-load uncertainty arising from forecast errors or intra-hour ramping needs, which are handled through separate products. CAISO implements this procurement process through its Residual Unit Commitment (RUC) tool, which is akin to PJM's RAC, but allows offer prices to be submitted for providing the service. The RUC then clears these products in a co-optimization with energy and other ancillary service reserve products based on submitted offers and accordingly sets the market clearing prices for these products. This implementation does not change the cleared quantities and clearing prices resulting from the Day-Ahead Market but procures the incremental or decremental supply to meet the forecast demand using residual supply.

ISO-NE is targeting the implementation of an Energy Imbalance Reserve (EIR) product in 2025, which is designed to address the lack of compensation, obligation and notice to resources needed to fill this energy gap. As with all the new reserve products introduced under ISO-NE's recently approved filing, the EIR product will be co-optimized with energy and other ancillary service reserve products in the Day-Ahead Market and will be structured as an energy call option. Before the Day-Ahead Market deadline, ISO-NE will set a strike price for every hour of the next operating day. Resources will then offer energy call options into the market that reflect: (1) expected close-out charges, based on expected hub energy prices and the strike price, (2) avoidable fuel or charging costs, and (3) a risk premium. Then, in real time, if LMP exceeds the calculated strike price set by ISO-NE, the call option is settled when the resource pays the difference between the strike price and LMP. If LMP is below the strike price, the resource keeps that revenue. This call-option design does not rely on settling the day-ahead reserve product against a corollary real-time product, which is necessary for a product like EIR that is addressing a risk that only exists day ahead.

PJM's Preliminary Design Perspectives

PJM proposes to explore the design and implementation of a day-ahead-only product that would account for the gap between the physical supply procured through the Day-Ahead Market and the PJM load forecast. This would be similar in intent to the Energy Imbalance Reserve product recently filed by ISO-NE and approved by FERC and would reflect reliability needs met through RAC into the Day-Ahead Market, thus better aligning PJM markets with operational needs. Procurement of the Day-Ahead Energy Imbalance Reserve (DA-EIR) product would be co-optimized with energy commitments in the Day-Ahead Market, meaning that the cost of procuring reserves would be evaluated and minimized along with the cost of energy commitments, allowing the market to economically pre-position the system based on the best currently available information. Given that this gap does not exist in real time, the DA-EIR requirement would only exist in the Day-Ahead Market and would not be carried into real time.

In addition to any gap between physical generation cleared in the Day-Ahead Market and the load forecast, operators also ensure that sufficient reserves are available to manage risk associated with average historical load forecast error and generator forced outages, also known as the Day-Ahead Schedule Reserve (DASR) requirement. Given that these risks are greater day ahead than in real time, these additional reserve needs could also be included in a day-ahead-only product like the proposed DA-EIR if the performance characteristics needed from these services were the same. However, if the nature of these reserve drivers is sufficiently different, particularly such that it leads to different resource obligations or differences in how resource performance is settled, these reserves would likely need be addressed in separate products. This is something PJM is actively exploring. **Table 2** provides a summary comparison of the two types of reserve needs addressed by operations outside of the Day-Ahead Market today. Some of the design trade-offs implicit in this decision are also discussed in the Requirement and Constraint Formulation section below.

Table 2. Comparison of the Day-Ahead Energy Gap and DASR Reserve Needs

Day-Ahead Energy Gap		
Reserves required to ensure that enough physical generation is available to meet the PJM load forecast		
Energy Gap	*= Load Forecast + Net-Scheduled Export – Physical Supply Cleared*	
Reserve need does not exist in real time. Therefore, a corollary product will not cleared in the Real-Time Market.	**Reserve need is based on the expected load forecast.**	**Because the energy gap is based on the amount of physical supply that is cleared, a trade-off could exist in the market between clearing more physical supply (and thereby reducing the energy gap) and procuring more reserves.**
DASR		
Reserves required to manage uncertainty associated with load forecast error and generator forced outages		
DASR	*= Load Forecast x (Avg. Load Forecast Error + Avg. Generator Forced Outage Rate)*	
Reserve need exists in real time, but at a lower level. Therefore, a corollary product might be cleared in the Real-Time Market.	**Reserve need is based on an uncertainty distribution around the expected forecast based on historical forecast error.**	**The reserve need is not directly linked to the amount of physical supply cleared supply in the Day-Ahead Market.**

Note that even after both reserve needs are reflected in the Day-Ahead Market, this will not eliminate the need for RAC, because there may be times when updated forecast information or generator forced outages require additional commitments after the Day-Ahead Market clears. However, these market reforms should reduce the number of out-of-market commitments that PJM needs to make day ahead.

Requirement and Constraint Formulation

The DA-EIR Requirement would be set based on the difference between the total physical generation committed through the Day-Ahead Market and the PJM load forecast plus net-firm export for each hour of the next operating day. The requirement would therefore change hourly, and DA-EIR would be procured on an hourly basis. The constraint in the Day-Ahead Market optimization could be formulated in a few different ways, which would have different implications for the optimization and market outcomes, and different attendant complexities. To begin, a few definitions to enable the discussion moving forward:

- **PJM day-ahead load forecast (load forecast):** The most recent available load forecast for each hour of the following operational day at the time the Day-Ahead Market runs

- **Cleared physical supply (physical supply):** The total energy commitments cleared through the Day-Ahead Market on physical resources capable of producing energy in real time
- **Cleared virtual supply (virtual supply):** The total energy commitments cleared through the Day-Ahead Market in Increment Offers
- **Total cleared energy (cleared energy):** The total energy commitments cleared through the Day-Ahead Market on both physical and virtual supply, minus cleared Decrement Bids (virtual demand)
- **Bid-in fixed demand (fixed demand):** The total fixed demand bid-in to the Day-Ahead Market. This does not include Price Responsive Demand.
- **Net bid-in firm export (net bid export):** Bid-in firm export – bid-in firm import
- **Net forecasted firm export (net forecasted export):** Forecasted firm export – forecasted firm import[6]

In the Day-Ahead Market optimization, the constraint that dictates how DA-EIR is procured could be formulated in three different ways as outlined below. Note that in these formulations, and specifically relevant for highlighting the difference between Options 2 and 3, everything on the left-hand side of the equality constraint is assumed to be a variable, while the right-hand side is assumed to be a fixed value.

Option 1:	DA-EIR ≥ load forecast + net firm forecasted export – fixed demand – net bid export
Option 2:	DA-EIR ≥ load forecast + net firm forecasted export – physical supply
Option 3:	DA-EIR + physical supply ≥ load forecast + net forecasted export

All three options procure DA-EIR to address the gap between the forecast and bid-in demand. However, only Options 2 and 3 also ensure that sufficient physical supply has been cleared to meet forecasted load. Additionally, Option 3 allows the optimization to trade off between clearing physical supply and procuring DA-EIR if the former is more economical, while Option 2 does not. Option 2 is included in this discussion because it would allow the DA-EIR requirement to be formulated strictly as a reserve service, which might allow the requirement to be more readily extended to address other reserve needs. Including it in the discussion also has the benefit of highlighting the effect that co-optimization has on market outcomes, which is a departure from using a sequential approach, such as the separate commitment PJM does today. For Option 1, the question of trading off between additional commitments and additional DA-EIR procurement is irrelevant because only the incremental difference between the forecast and bid-in demand is required to be hedged with physical supply resources. A simple example is provided below to highlight the difference between how these three different constraint formulations would lead to different market outcomes.

Assume there are two physical generation resources, R1 and R2, and one Increment Offer, I1. The energy offer information for each of the market participants is given in **Table 3**. Assuming that DA-EIR is cleared based on 60-minute resource capability, the amount of DA-EIR a resource would be eligible to provide would be based on its 60-minute ramping capability.

[6] If PJM forecasts interchange and needs to mitigate the risk of any delta between forecasted and bid-in interchange for operational reliability, this formulation will provide the flexibility to do so. However, if PJM does not need to operationally forecast interchange day ahead (as is the practice today), then the net forecasted firm export value should be set to be equal to the net bid-in firm export.

Table 3. Example Energy Offers

Market Participant	Price	MW	Ramp
R1	$10	200 MW	1 MW/min.
R2	$50	200 MW	0.5 MW/min.
I1	$20	20 MW	

For simplicity, there are no Decrement Bids, no Price Responsive Demand and no net export in this example. Bid-in demand is 250 MW, and the load forecast is 275 MW. The total physical supply in the system will be the sum of the energy commitments given to R1 and R2. The total virtual supply will be the energy commitment given to I1. The energy balance constraint in the optimizations requires that the total cleared energy (the sum of the physical and virtual supply) be exactly equal to the bid-in demand of 250 MW.

Physical supply	*= R1 energy + R2 energy*
Virtual supply	*= I1 energy*
Cleared energy	*= physical supply + virtual supply – virtual demand*

In the absence of a DA-EIR Requirement, the Day-Ahead Market would assign R1 a 200 MW energy commitment, R2 a 30 MW energy commitment, and I1 a 20 MW commitment. R2 would be marginal, setting the system marginal energy price (SMP) at $50.

Cleared energy	*= 230 MW + 20 MW – 0 MW = 250 MW*

Now, consider the implications of each of the above sets of constraints for clearing the DA-EIR product. In Option 1, the amount of DA-EIR would simply be based on the difference between the bid-in demand and the load forecast as outlined below.

Option 1	*DA-EIR ≥ load forecast + net firm forecasted export – fixed demand – net bid export*
	DA-EIR ≥ 275 MW + 0 MW – 250 MW – 0 MW = ***25 MW***

There is sufficient headroom and ramping capacity available on R2 to provide this 25 MW through unloaded capability. The resource would therefore have no LOC, and the pricing outcomes would be very similar to status quo described above. Additionally, the DA-EIR service would not guarantee that all of the forecasted load could be met through physical resources since 20 MW would be supplied from the virtual supply.

In Option 2, where the DA-EIR constraint requires that sufficient DA-EIR be procured to hedge the physical risk associated with cleared virtual supply, the DA-EIR Requirement would be 45 MW.

Option 2	*DA-EIR ≥ load forecast + net firm forecasted export – physical supply*
	DA-EIR ≥ 275 MW + 0 MW – 230 MW = ***45 MW***

R2 no longer has sufficient available ramping capability to provide this service using unloaded capacity, as it can provide a maximum of 30 MW in 60 minutes based on its 0.5 MW/min. ramp. Therefore, R1 would need to be backed down to provide the additional 15 MW and would therefore incur a LOC of $40/MWh.

Finally, in Option 3, the optimization will evaluate the trade-off between committing more physical generation and procuring more DA-EIR to meet the DA-EIR Requirement to identify the cost-minimizing outcome. In this scenario, the production cost minimization would decrease the energy commitment awarded to I1 in favor of awarding a larger energy commitment to R2. Because I1 now has available capacity, the system marginal price becomes $20 based on its marginal cost, and the LOC associated with cleared DA-EIR becomes $30. **Table 4** provides a summary of these results.

Table 4. Example Results of the Three Different Constraint Formulation Options

	Energy Assignment			*DA-EIR Assignment*				
Scenario	**R1**	**R2**	**I1**	**R1**	**R2**	**System Energy Price**	**DA-EIR LOC**	**Total Production Cost**
Status Quo (No DA-EIR)	200 MW	30 MW	20 MW	N/A	N/A	$50	N/A	$3,900
Option 1	200 MW	30 MW	20 MW	0 MW	30 MW	$50	$0	$3,900
Option 2	185 MW	45 MW	20 MW	15 MW	30 MW	$50	$40	$4,500
Option 3	200 MW	45 MW	5 MW	0 MW	30 MW	$20	$30	$4,350

The implementation of Option 1 is by far the simplest. The requirement is based solely on inputs to the market rather than having an inherent interdependence with cleared energy. The disadvantage of Option 1 is that it does not provide a physical hedging mechanism that would guarantee that – between energy and DA-EIR assignments – all forecasted load could be met by physical resources with binding day-ahead commitments.

Option 2 could be formulated as a separate clearing process from the Day-Ahead Market commitment, using the outputs of that optimization as an input to this process, treating the cleared physical generation as a fixed quantity. The primary differentiator for Option 2 when compared with Option 3 is that it allows the requirement to be treated as a separate and discrete reserve service rather than as a product that is substitutable with energy. While this may be less optimal, it could provide additional flexibility in how the requirement is structured. For instance, if PJM has additional reserve needs day ahead that it would like to include in this product definition, that might be more appropriate if the resources assigned to provide this service are strictly treated as reserves, rather than allowing the optimization to clear more physical supply to reduce the reserve requirement. Additionally, fixing the energy gap quantity could simplify the optimization itself, which could have advantages if the ultimate market design would otherwise introduce interdependences that could lead to computational challenges. However, if this product is intended to solely address the day-ahead energy gap and any additional complexity does not present a challenge within the full market design, then Option 3 may be the better solution, because it is inherently more efficient, as it allows for product substitution between cleared energy and DA-EIR.

Product Definition Resource Eligibility Requirements

PJM's current thinking is that the DA-EIR would be a 60-minute product to align with the hourly day-ahead load forecast. Resources would be cleared based on their achievable megawatt output within 60 minutes, and both online and offline resources (i.e., both resources with and without an energy commitment in the hour) would be able to provide the service. To be eligible to be assigned DA-EIR, a resource would need to be able to sustain its assigned megawatt output for at least 60 minutes. To align with operational needs and to mitigate the risk of resources failing to start, offline resources (i.e., resources without an energy commitment for a given hour) would need to be able to come online and become dispatchable within 30 minutes to be eligible to provide DA-EIR. Offline resources would also be ineligible to receive a DA-EIR assignment in any hour within a minimum downtime window based on their energy commitments for the day.

Locational Procurement and Deliverability

As DA-EIR would be procured to meet forecasted load, deliverability of the service is important. Currently, when PJM makes commitments through RAC, network constraints are modeled in that tool and reliability studies are run to ensure that any subsequent commitments will not create constraint control issues. One of PJM's central goals is to design the markets to better align with operational practice, and to not do so in this instance could ultimately mean that PJM's markets might procure a service that did not provide its intended reliability value. To the extent possible, the reliability and deliverability constraints that would require dispatchers to commit different or additional resources should be modeled in the market. This will reduce out-of-market commitments, promote market efficiency and transparency, and align incentive signals with operational needs.

Ultimately, the locational procurement of DA-EIR may have implications for how the product is settled. Using an energy call-option settlement structure akin to ISO-NE's approach where a strike price is determined day ahead may be more complicated if the service is not procured at the RTO level. More work will need to be done to study possible approaches and their resulting market implications, but if a single strike price were used, it could make it challenging to evaluate resources with the same or similar offers at different settlement locations. Alternatively, setting different strike prices at different locations in the system could add significant complexity to the market design.

Performance and Settlement

Unlike Synchronized Reserves, which are deployed through operator action during an event, DA-EIR would be "deployed" through normal energy dispatch, and resources' performance obligation would entail: (a) being available for dispatch and (b) following dispatch instructions. Resources would be expected to bid into the Real-Time Market their ability to provide energy in each hour in which had a reserve assignment, at a minimum, at a level consistent with their DA-EIR and energy commitments. Resources would then be expected to follow energy dispatch instructions in real time.

PJM has been exploring possible ways to settle the obligation entailed with a DA-EIR assignment, and it has raised several important questions about how this market and product should be designed. In PJM's existing reserve market constructs, reserves are procured based solely on their availability costs without reference to their deployment or dispatch costs. For a product like Synchronized Reserves, which is deployed during an event, this may make sense. However, for a product like DA-EIR, which is being procured to ensure that sufficient generation is available to serve forecasted load, this may not be as appropriate. A very simple example is provided below to illustrate some of the limitations that may exist if DA-EIR is cleared such that only resource availability costs are minimized without consideration of real-time costs.

Assume there are two resources, R1 and R2, which have different operating postures. R1 has no avoidable costs day ahead to provide reserve services. R2 could be available to run in real time but must make arrangements at some cost day ahead to be available to provide reserves (and by extension, energy in real time). Based on the day-ahead energy prices, neither resource will get an energy commitment, but both are eligible to provide DA-EIR. For simplicity, both resources have sufficient capability to meet all of a 100 MW DA-EIR requirement. **Table 5** provides the day-ahead offers for R1 and R2.

Table 5. Example Resource Offers

Day-Ahead Offer	R1	R2
Energy	$150	$50
DA-EIR (i.e., availability costs)	$0	$25

Now consider two different scenarios: one where the market clears DA-EIR solely based on availability costs, and a second where the market minimizes total costs when clearing DA-EIR. **Table 6** and **Table 7** provide notional results for each scenario.

Table 6. Results for Scenario 1 Where the Availability Costs Are Minimized

Resource	DA-EIR			Real-Time Energy			Total
	Offer	Commitment	Cost	Offer	Commitment	Cost	
R1	$0	100 MW	$0	$150	$15,000	$15,000	$15,000
R2	$25	0 MW	$0	N/A	0 MW	$0	$0
Total			$0			$15,000	**$15,000**

Table 7. Results for Scenario 2 Where Both Availability and Deployment Costs Are Minimized

Resource	DA-EIR			Real-Time Energy			Total
	Offer	Commitment	Cost	Offer	Commitment	Cost	
R1	$0	0 MW	$0	$150	$0	$0	$0
R2	$25	100 MW	$2,500	$50	100 MW	$5,000	$7,500
Total			$2,500			$5,000	**$7,500**

First and foremost, procurement of DA-EIR is intended to address a reliability need and to better align PJM's markets with what's needed for operations. However, if the expectation is that the quantity of energy procured as DA-EIR will be needed in real time to meet forecasted demand, the most efficient solution may sometimes be to incur additional but lesser costs day ahead to avoid the likelihood of incurring greater costs in real time. The higher the probability that reserves will be converted to energy, the more valuable it would be for PJM's markets to be able to do that more holistic cost-benefit analysis.

In its EIR product design, ISO-NE has addressed this by designing its day-ahead reserve products as energy call options. ISO-NE will set a strike price day ahead, and then resources will bid in their day-ahead reserve offers, which would include their avoidable costs to maintain availability, their expected settlement costs given that strike price, and a risk premium. Then, in real time, if LMP exceeds the strike price set by ISO-NE, the call option is settled when the resource pays the difference between the strike price and LMP. If LMP is below the strike price, the resource keeps that revenue.

Unlike PJM's existing reserve products, this call-option design does not rely on settling the day-ahead reserve product against a corollary real-time product, which is important for a product like the DA-EIR product currently under consideration, because the service will not be procured through the Real-Time Market. It also provides an endogenous mechanism for hedging or partially mitigating high prices in real time, which is a significant benefit.

The call-option market design also has the advantage of relative simplicity in how it's settled. No evaluation of a resource's performance or investigation of whether the procured capacity was in fact available on the resource in real time is necessary. However, it does come with different complexities, including the need to develop a methodology for setting the strike price, and this would be further complicated if the reserve service is not procured at the RTO level, which PJM anticipates will likely be necessary, given congestion within PJM's footprint.

As an alternative, the DA-EIR service could be settled based solely on resource performance in real time, and there would be consequences for non-performance more akin to PJM's existing reserve products. This would entail developing processes for doing this evaluation as well as establishing financial settlement consequences that appropriately reflect the impact to the system when a DA-EIR resource fails to provide the procured reliability service. The performance evaluation would likely involve two separate evaluations, one to determine whether the resource is available in real time to provide the service, and one to evaluate whether – if called upon to convert procured reserves into energy – the resource follows PJM dispatch instructions. Possible options for settlement consequences when resources fail to perform could include a clawback of the DA-EIR revenue received or payment for replacement energy based on the real-time LMP. The latter option could help mitigate high real-time prices, and these settlement risks would then be reflected in resource offers.

One concern that ISO-NE had, which in part led them to develop the energy call-option structure, was that resources might not be sufficiently incentivized to make themselves economic to provide energy in real time. For example, assume a gas resource submitted an offer to provide DA-EIR based on its costs to make fuel arrangements day ahead and received an award for DA-EIR. Then, in real time, gas prices are higher than they were day ahead, and the resource has the option to sell back the gas it procured at a profit. This resource's profit-maximizing behavior, and in fact its marginal cost, is now not based on what it spent to make fuel arrangements yesterday, but on the price of gas in real time. It might then update its real-time energy offer to reflect that, and if – because of this increase – that resource is no longer economic, it will not be called on to convert that DA-EIR assignment into energy.

If PJM ultimately determines that a call-option design is not feasible within its footprint, PJM will evaluate whether there are alternate ways to reflect deployment costs into its market clearing for DA-EIR. These may also be developed with complementary economic obligations in real time for resources with a day-ahead reserve assignment. For example, the market rules might be structured such that resources would have to make any megawatt-hours cleared for DA-EIR available to the market in real time based on their day-ahead energy offers. Ultimately, the market design for this product will hinge on two central questions that need to be considered moving forward:

1 | Is DA-EIR purely intended to provide the identified reliability need, or – to the extent possible – should real-time market outcomes be considered in its procurement?

2 | Can real-time time deployment costs be practically represented in clearing DA-EIR in a way that consistently improves market efficiency?

Days of Elevated Operational Risk

Everything previously discussed in this paper has been in reference to the market design for a typical operating day. PJM recognizes that additional provisions are necessary to maintain reliability during times of elevated risk. PJM believes this will need to be considered comprehensively and so proposes to explore how to align reserve markets with operational needs during emergency conditions in the context of the complete set of reforms.

Ramping and Uncertainty Reserves (RUR)

Challenges To Be Addressed

PJM's Uncertainty Needs Are Not Accurately Reflected in Existing Market Structures

In operating the electric power system, PJM relies heavily on imperfectly known and forecasted information, including forecasted demand, forecasted renewable generation, and probable levels of resource availability or outage. This dependence is likely to increase moving forward as more variable wind and solar resources enter the system. One of the key drivers for flexibility and reserve needs within PJM system is the need to effectively manage these uncertainties.

Under the DASR construct that existed before 2022 when Reserve Price Formation was implemented, PJM procured day-ahead reserves to meet the average generator forced outage rate and the average load forecast error, multiplied by forecasted peak demand for the coming operating day. This allowed PJM's reserve quantities to: (a) reflect how reserve needs change as a function of system loading and (b) acquire reserves to manage two critical uncertainties. When the reforms under Reserve Price Formation were designed, they included changes to the ORDCs that set the value of reserves based on the probability of falling below the minimum reliability requirement driven by a comprehensive set of uncertainties, including those driven by load, wind, solar, interchange and forced outages. When this portion of the original package was removed through the FERC Remand Order, it created a gap in PJM's reserve market, which now no longer recognizes the value of reserve services in managing these uncertainties.

Day ahead, PJM dispatchers ensure that, at a minimum, there are sufficient reserves available on the system to meet the DASR requirement. During days with high levels of forecasted renewables or days when generator outage risks are higher, operators may determine that additional reserves are needed. Since these reserve quantities are not procured through the Day-Ahead Market, operators must take out-of-market actions to ensure that enough reserves are available. Often this is done through out-of-market generator commitments, where resources are asked to run at their economic minimum and then, if they do not fully recover their cost to operate through the market, given uplift payments to make them whole. This leads to market inefficiency and fails to transparently reflect the need for these services, while potentially suppressing LMPs.

In real time, RT SCED provides dispatch instructions to generation resources based on forecasted real-time load, scheduled interchange and renewable resource forecasts.[7] When these forecasts are not realized as expected, more flexible capacity is needed in future interval(s). However, this flexible capacity is not currently reserved through RT SCED, which may leave insufficient flexibility available. In the absence of any market mechanism to value and procure this flexible capacity, operators need to take out-of-market actions for reliable operation, such as introducing load biases into RT SCED, which has an impact on prices without sending clear flexibility incentive signals.

PJM's Current Dispatch Cannot Position the System for Upcoming Ramping Needs

In addition to maintaining flexibility to manage forecast uncertainties, PJM may require additional flexible ramping capability and methods for pre-positioning the system to manage upcoming forecasted ramping needs. Because RT

[7] Either PJM's forecast or those reflected in resources' bid-in parameters

SCED is a single interval dispatch – it does not consider the ramping needs of future intervals when making dispatch decisions in the current interval. For example, take a system where there are three kinds of generation resources available to meet load over the next two hours: (1) fast-ramping online resources with very low marginal energy costs, (2) slow-ramping online resources with higher marginal energy costs, and (3) offline Fast-Start Resources with high commitment costs. For a particular upcoming ramping period, a two-hour look-ahead commitment and dispatch optimization determines that the most efficient outcome to meet the expected net-load ramp is to begin ramping up the slower moving, slightly more expensive online resources now. This will retain ramping and headroom capacity on the faster-moving resources for later and allow all of the demand over the next two-hour period to be met by online resources without the need to incur the high cost of committing the offline units.

Now imagine that a single interval is evaluating the dispatch instructions to send to resources for the next target time, roughly 10 minutes in the future. It has no insight into anything forecast beyond the next 10 minutes and has sufficient low-cost energy available to meet current demand on inexpensive, fast-ramping resources. It will therefore dispatch these least-expensive resources up to meet that demand. This will continue every interval until this lower-cost energy is exhausted. At some point, there will no longer be sufficient ramping flexibility available online to meet the upcoming ramping needs, and so operators will be forced to bring online fast-start, high-commitment cost resources to meet demand.

This is a challenge that exists today and is sometimes addressed by operators through the introduction of load biases into RT SCED cases to pre-ramp resources. As mentioned earlier, this can impact prices but does not send clear or consistent pricing signals, in that it is not valuing the actual service required. Additionally, this can have consequences for the deployment of regulation services, which may or may not be needed. Moving forward, as PJM projects increasingly large net-load ramping events through the energy transition, this issue will be exacerbated.

Practices in Other ISOs/RTOs

To manage uncertainty driven by increasing net-load forecast error, NYISO plans to incorporate its net-load uncertainty as an incremental quantity in its existing 10- and 30-Minute Reserve Requirements. In the Day-Ahead Market, this increase in the 30-Minute Requirement will be based on day-ahead net-load forecast uncertainty. In the Real-Time Market, the incremental 30-Minute Reserve Requirement will be based on 60-minute-ahead net-load forecast error and the incremental 10-Minute Reserve Requirement will be based on 30-minute-ahead net-load forecast error in both markets. This uncertainty portion of the reserve requirements will be distributed locationally across reserve subzones based on where net-load forecast error is highest, driven largely by resource mix. The proposed implementation of this incremental uncertainty requirement is in 2025.

Additionally, to address longer-look-ahead net-load forecast error, NYISO proposes implementing a new 60-Minute Reserve product based on four-hour net-load uncertainty with a four-hour-duration availability requirement. This new uncertainty product will not nest or overlap with NYISO's existing 10- and 30-minute products, meaning its requirement would be met separately. Studies done by NYISO showed that the four-hour uncertainty and duration requirement covers a significant amount of observed net-load forecast error while simultaneously aligning with the time to start of the bulk of their generation fleet, providing the time needed to bring additional resources online to backfill this service. NYISO proposes implementing this new product in 2026.

MISO has implemented a 30-minute Short-Term Reserve (STR) product in both its real-time and day-ahead markets to manage uncertainty, which was previously handled through out-of-market actions. MISO's STR is similar to PJM's 30-Minute Reserve product and is included in both the Day-Ahead and Real-Time Market co-optimizations. The purpose of this product is threefold: to manage transfer between the MISO north and MISO south regions, to restore transmission flows within limits following a contingency, and to ensure sufficient available flexibility for managing uncertainties associated with net-load forecast error. MISO considers net-load variations from 30 minutes to three hours when setting the STR requirements, which come out of a machine learning model that predicts high-, medium- or low-risk profiles for the current system conditions. MISO uses this requirement in both day ahead and real time.

In 2016, MISO also implemented a flexible ramping product to address both forecasted and unforecasted variability in its net-load, largely driven by load, intermittent generation resources and net-scheduled interchange. MISO studied both increasing their regulation requirement and increasing their synchronized reserve requirement as alternative ways to procure this additional ramping need. However, these alternative solutions resulted in higher production costs when compared with the flexible ramping product.[8] MISO's flexible ramping product has two components: Flexible Ramping Up and Flexible Ramping Down. It procures both based on the net change in demand between the current interval and the interval immediately following as well as upcoming net-load uncertainty for a forward time horizon of 10–25 minutes.[9] All resources providing this ramp service must be able to convert this ramp capability into energy within 10 minutes. In the Day-Ahead Market, this 10-minute window is scaled to one hour to accommodate the hourly time resolution. This flexible ramping product is procured at the ISO level; however, specific deployment constraints are considered during procurement to ensure the procured ramp capability is deliverable when needed.

SPP implemented a ramp product to procure the ramp capability needed for future intervals to manage both forecasted and unforecasted intra-hour ramping events using a market-based approach. SPP's ramp capability requirement is determined based on two calculations. The first looks at the expected intra-hourly change in net load. For the uncertainty portion of the ramp requirement, SPP looks at the historical net-load forecast error driven by errors in wind and solar generation.

SPP also has an Uncertainty Reserve product, which manages uncertainty associated with renewable resource generation across a longer time horizon.[10] The currently implemented Uncertainty Reserve product procures one-hour flexible capacity. However, operators are also concerned about flexibility across many additional time horizons, including two hours, three hours and up to several days ahead. SPP is therefore monitoring the need to implement additional uncertainty reserve products moving forward. SPP's Uncertainty Reserve Up Product can be met by the Regulation Up, Contingency Reserve and Ramping Capability Up products. Product substitution may therefore occur when the procurement of these services is co-optimized with energy.

Like SPP's ramp product, SPP's Uncertainty Reserve requirement is also set by the sum of the forecasted and uncertainty-driven flexibility needs in future intervals. The forecasted component is based on the hourly forecasted

[8] Ramp Capability Product Design for MISO Markets, MISO, Dec. 22, 2013

[9] Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve (PDF), MISO, March 2024

[10] Submission of Tariff Revisions to Add Uncertainty Reserve Products to the Integrated Marketplace (PDF), SPP, Jan. 28, 2022

net-load change between each hour. The uncertainty component of the requirement is based on historical net-load forecast error over the prior twelve months for a given hour. The 97th percentile of the forecast error is used to set the hourly uncertainty component. As the Regulation Up, Contingency Reserve and Ramp Capability Up products can fulfill the Uncertainty Reserve service, these procurement quantities are subtracted from the total Uncertainty Reserve requirement.

To address the forecast errors that exist between the Day-Ahead and Real-Time Markets, CAISO has implemented a new Imbalance Reserve product. This Imbalance Reserve is a 15-minute ramp product and supplements CAISO's Reliability Capacity product, which is a 60-minute product. Imbalance Reserve provides flexibility to respond to intra-hour balancing needs. As discussed below, CAISO uses a multi-interval dispatch optimization to manage forecasted changes in net-load. However, even with multi-interval dispatch, CAISO found that when system conditions changed in subsequent intervals due to forecast errors, the system would sometimes lack sufficient ramp capability to get a feasible dispatch solution. CAISO therefore introduced a flexible ramping product to manage intra-hour forecast uncertainties caused by load and variable energy resource forecast error.[11] CAISO has implemented this flexible ramping product in both its 15-minute and five-minute markets. Implementation in the 15-minute market is intended to ensure that enough ramp capacity is available to meet the need for the upcoming 15-minute market solution and the three corresponding five-minute solutions. Procurement in the five-minute market is to ensure that enough ramp capability is available to meet demand in future five-minute dispatch intervals.

CAISO and NYISO use multi-interval dispatch to help pre-position the system for forecasted ramping needs. Multi-interval dispatch performs Security Constrained Economic Dispatch for multiple intervals, which allows pre-ramping of resources to maximize the economic use of available ramp capability by trading off the costs between intervals. Both ISOs optimize the dispatch over the next hour on a rolling basis, where the first interval becomes the binding dispatch instruction for the next five minutes, and the remaining dispatch intervals are advisory. The objective of the optimization is to minimize production costs across all modeled intervals, and multi-interval dispatch may dispatch resources out of merit in the current interval to preserve additional ramp capability for future intervals.[12] If a resource is dispatched down out of economic merit order from its economic maximum to reserve ramp capability for future intervals, the market must replace this energy from higher-cost resources.

In both CAISO and NYISO, only the results of the first interval are settled. If future prices do not materialize as forecasted, this can lead to a misalignment between market signals and the profit-maximizing behavior of resources, which can result in disincentives to follow dispatch instructions or uplift payments to make resources whole for financial losses. Both CAISO and NYISO help to mitigate this issue with their rules for settling uninstructed deviation.

PJM's Preliminary Design Perspectives

PJM proposes to design ramping and uncertainty reserve (RUR) product(s), which would be used to ensure that sufficient flexibility is available on the system to manage operational uncertainty and to meet the forecasted ramping

[11] Flexible Ramping Product Refinements, CAISO, Aug. 31, 2020

[12] Ramp Capability Dispatch and Uncertain Intermittent Resource Output (PDF), Rutgers Center for Research in Regulated Industries, June 2018

needs in future intervals. These reserves would be procured both day ahead and in real time, though likely in different quantities, as discussed later in this section. PJM views these products as critical to ensuring that enough flexibility exists within the system to manage the increasing uncertainty and variability associated with the energy transition. Almost every other RTO/ISO in the country has implemented or is in the process of implementing these types of products.

Factors Driving Uncertainty

One of the key risks that PJM must manage as the energy transition progresses is increasing operational reliance on imperfect information. As more variable, weather-driven resources enter the system, more dispatchable flexibility will be required to ensure reliable operations when resources produce either more or less than forecasted. This will be particularly critical during times of tight operational conditions, high demand or large net-load ramps.

PJM has identified the following set of factors that drive operational uncertainty, which should be explored in considering the design of new uncertainty reserve products:

1 | Net-load forecast error, which would include load, wind and solar forecast error, as described below

2 | Generator forced outage rates

3 | Net-interchange error

Additional detail on the net-load definition used here:

- **Net-load:** The difference between the total electricity demand and the amount of energy generated from solar and wind *(i.e., net-load = load – wind generation – solar generation)*
- **Net-load forecast error (NLFE):** The difference between the forecasted net load and the actual net load that ultimately materializes. In the data presented below, the percent net-load forecast error is calculated as:

NLFE(%) = *(net-load forecast – net-load actual) / net-load actual*

Forecast error tends to decrease as the time of delivery approaches. Therefore, PJM expects to require more reserves to manage uncertainty further ahead of the time of delivery and for these reserve needs to decrease as the uncertainty resolves. **Figure 3** and **Figure 4** provide the 97.5 and 2.5 percentile net-load forecast error for the 2023/2024 Delivery Year for five minutes ahead out to 24 hours ahead of the time of delivery. Note that the 2.5 percentile error, which are negative values given the sign conventions described above, would reflect ramping up flexibility needs, while the 97.5 percentile error reflects ramping down flexibility needs. These figures provide some insight into how uncertainty resolves as the effective time approaches.

Figure 3. 2.5 and 97.5 Percentile Net-Load Forecast Percent Error One to 24 Hours Ahead of Delivery Time During the 2023/2024 Delivery Year

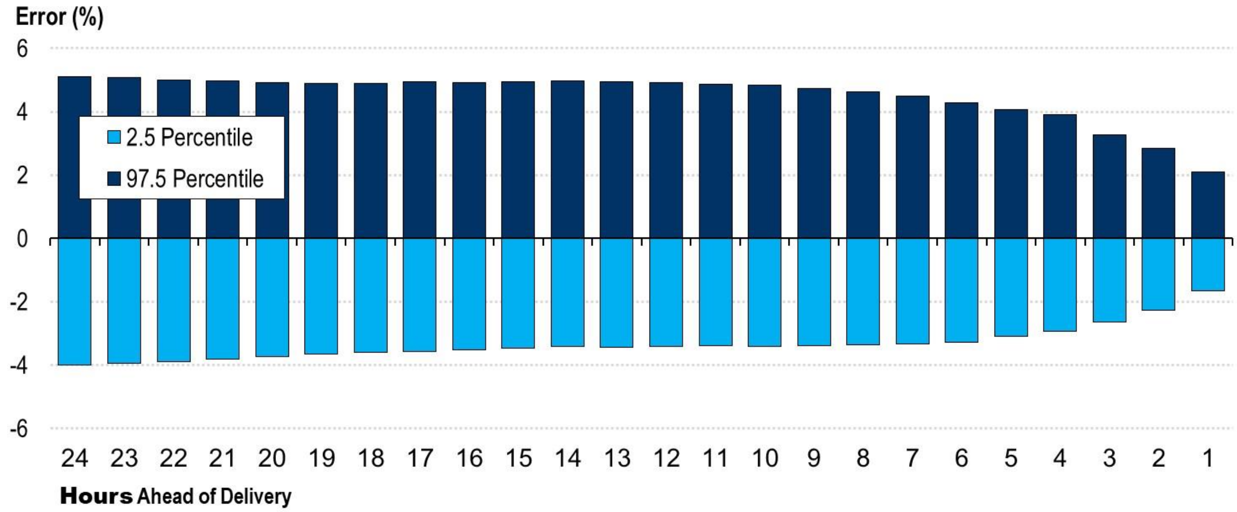


Figure 4. 2.5 and 97.5 Percentile Net-Load Forecast Percent Error Five to 55 Minutes Ahead of Delivery Time During the 2023/2024 Delivery Year

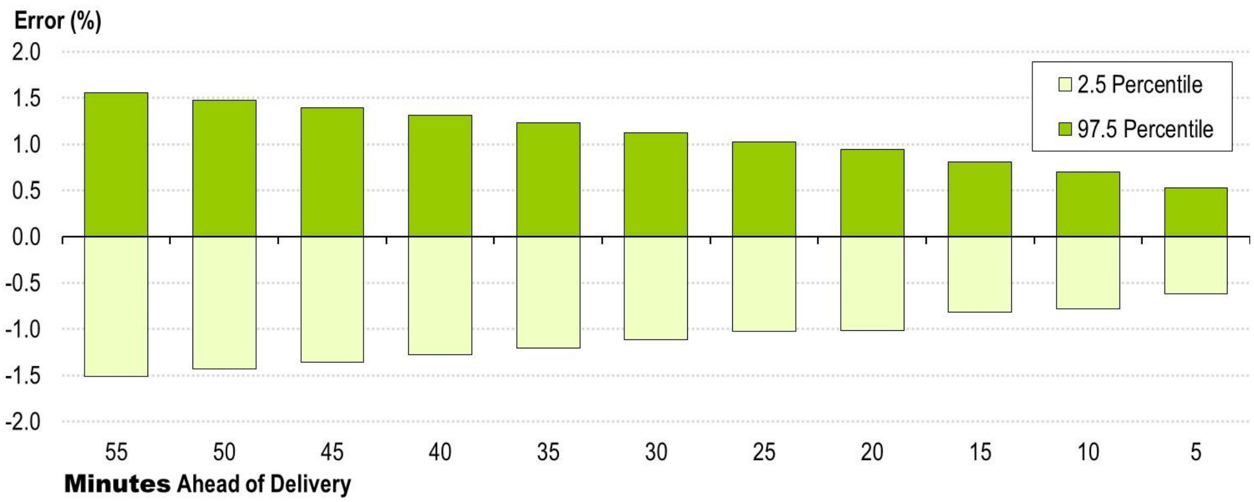


Figure 3 and **Figure 4** illustrate that while the net-load uncertainty does gradually decrease between 24 hours and seven or eight hours ahead of the time of delivery, it begins to decline more sharply after that point.

Challenges in Implementing Multi-Interval Dispatch to Address Forecasted Ramp

As touched on previously, multi-interval dispatch (in contrast to PJM's existing single-interval RT SCED) could address forecasted ramping needs by allowing slower-moving resources to be ramped proactively to meet forecasted demand in upcoming intervals. Recall the narrative example posed previously of a system with three types of resources: fast-ramping inexpensive resources, slow-ramping more expensive resources and offline Fast-Start Resources with high commitment costs. Entering a ramping period, a multi-interval dispatch optimization might determine that the most cost-effective way to meet demand over the next two hours is to pre-ramp more expensive, slower-moving resources earlier to avoid having to incur high commitment costs later. A single-interval dispatch would not be able to evaluate those intra-temporal trade-offs and would instead ramp up the least expensive resources to meet demand in the current interval. From this example, it may seem that multi-interval dispatch is inherently superior to single-interval dispatch in terms of promoting least-cost, market-efficient dispatch, and in many respects it is. However, there are some important caveats that need to be understood when considering implementing multi-interval dispatch in practice.

1 | The future may not materialize as forecast. Given that the forecast entails some level of uncertainty, it is possible that future system conditions – and by extension, energy prices – may not materialize as expected. Where significant deviations occur, this could lead to material changes to resource compensation through PJM's energy markets, which could require out-of-market uplift payments and potentially suppress prices.

2 | If only the first interval in a multi-interval dispatch solution is settled, it can lead to unintuitive pricing outcomes and disincentives to follow PJM dispatch. Pre-ramping a more expensive resource in one interval in preparation for expected energy needs in a future interval inherently involves dispatching resources out of merit order. A more expensive resource is dispatched up, although this dispatch is not justified by the real-time LMP, and that dispatch is necessarily displacing energy that would have been produced by a less expensive resource. This will tend to have price suppressing impacts. Given the uncertainty of future LMPs, the profit-maximizing behavior for resources might be to operate based on current LMPs rather than to follow PJM dispatch instructions in expectation of future LMPs.

3 | Multi-interval settlement would entail considerable additional complexity. Currently, neither NYISO or CAISO, who are the two ISOs currently using multi-interval dispatch, settle any of the intervals beyond the first. While an area of research and interest, PJM is concerned that implementing a multi-interval dispatch framework would be too complex to be feasible at this time.

These challenges lead PJM to the preliminary conclusion that any attempt in PJM's markets to allow the pre-ramping or pre-positioning of resources to manage upcoming forecasted ramping needs would have to be handled through the inclusion of a forecasted ramp component in any ramping/uncertainty reserve product(s), similar to the approach taken by SPP and MISO.

Contrast the scenario posed in the second item above with another where the resource being held down to provide future flexibility needs is given a reserve assignment. That resource, which might otherwise be marginal, is now compensated through the reserve market clearing price for any LOC it might need to incur and is therefore indifferent to providing reserves or energy in that interval. This resource can no longer be used to meet the next unit of energy demand because its available capacity is consumed by its reserve commitment, which causes another resource, perhaps a slower-moving resource at a slightly higher price, to be dispatched up economically. This second resource now becomes marginal and sets price, aligning its economic incentive with its dispatch instructions.

Including Ramping and Uncertainty in Existing PJM Reserve Structures

As discussed above, NYISO intends to extend its existing reserve requirements to include the flexibility needed to manage uncertainty associated with its net-load forecast error. NYISO is pursuing this path in part because it will simplify and expedite implementation of these uncertainty reserve products. PJM could explore a similar approach, and it may make sense to do so, particularly with PJM's existing 30-Minute Reserves. PJM has already identified that its 30-Minute Reserve product does not appropriately capture operational risk or align with dispatcher needs. Given that, PJM could pursue redefining its 30-Minute Reserve product to align with its uncertainty flexibility needs, and doing so might provide an avenue to get these reforms implemented earlier than would otherwise be possible. This would require reevaluating aspects of PJM's existing 30-Minute Reserve product design, including whether new locational deliverability requirements will have to be introduced, changing the procurement quantities to better align with operational risk, whether the existing resource eligibility requirements need to be modified, and whether reforms are needed to existing performance evaluation and settlement rules for resource non-performance.

Locational Procurement and Deliverability

Locational deliverability of the ramp and uncertainty reserve service is important. Because online ramping and uncertainty reserve products are often cleared based on LOC, several other ISOs, including CAISO and SPP, have seen these products clear on resources behind binding constraints. CAISO has changed its economic dispatch engine to ensure that its ramp product be simultaneously deliverable with energy. It does this by running two separate dispatch scenarios in addition to the base scenario that ultimately determines energy dispatch and price: one scenario also deploys all ramping up reserves, and the second also deploys all ramping down reserves. PJM intends to take lessons learned from the work done in other regions and to closely evaluate how the network and operational limitations that drive reliability needs can be appropriately represented in PJM's markets, recognizing that this may introduce implementation challenges that will have to be addressed.

Performance and Settlement

Similar to DA-EIR, ramping and uncertainty reserves would be "deployed" through normal energy dispatch, and resources' performance obligation would entail: (a) being available for dispatch and (b) following dispatch instructions. One key difference between an uncertainty-driven reserve product and PJM's existing reserve products is that it is likely that more uncertainty reserves will need to be carried day ahead than in real time. NYISO's market design will allow their day-ahead reserve requirements to be consistently greater than their real-time requirements. PJM is evaluating this approach, but has open questions about whether there could be implications for resource performance incentives. These concerns might be mitigated by introducing new performance evaluation and settlement rules, but more work needs to be done to evaluate the implications of these design decisions and to ensure coherence across the market design.

Cost Allocation

Procuring these new reserve services will entail costs, and how those costs are allocated will need to be determined. Today, the costs associated with ancillary services in PJM are allocated to load based on a load ratio share because these reliability services primarily benefit consumers. That will generally be true of any new uncertainty reserve products that PJM introduces as well. However, given that the need for these new uncertainty reserve products is likely to grow significantly and that need is directly attributable to the participation of certain resource types, a reasonable argument could be made that the cost of these reserve products should be shared across all market participants based on what is driving the need for these services. Allocating ancillary service costs based on attribution would not be straightforward, which is perhaps why none of the ISOs/RTOs have currently gone down that path. The need for many of PJM's current ancillary services is at least partly attributable to supply resources today; for example, regulation is in part needed to manage uninstructed resource deviation. Cost allocation for new reserve services will need to be considered within the broader energy and ancillary services market design to ensure coherency and consistency.

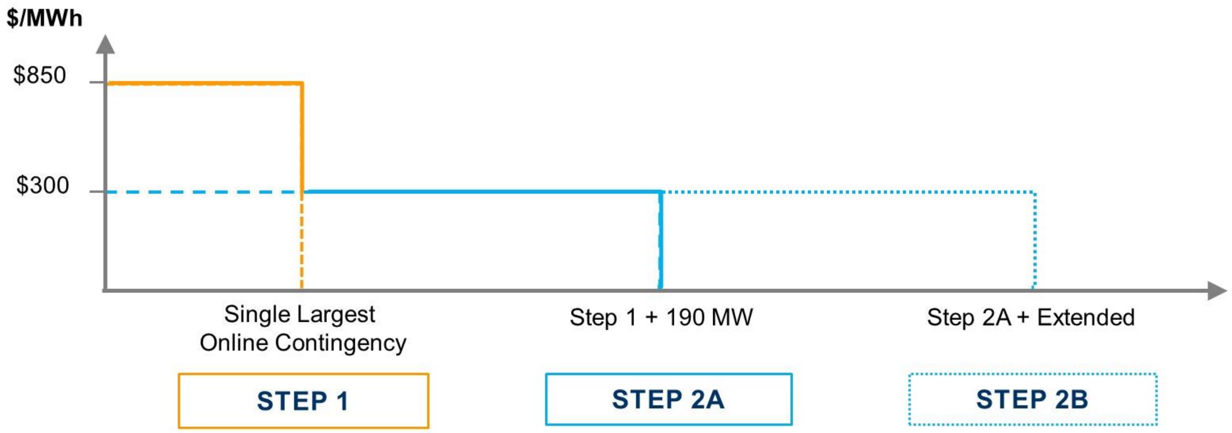
Enhancements to PJM's Existing Reserve Markets

Operating Reserve Demand Curves

Background and History

PJM's current ORDCs contain two steps: a $850/MWh penalty cost and a $300/MWh penalty cost. The megawatt value of the first step of the ORDC is set by the reserve reliability requirement of each reserve service. The second is the reliability requirement plus a 190 MW adder, which may be further extended during emergency conditions. **Figure 5** shows the current Synchronized Reserve ORDC.

Figure 5. Synchronized Reserve Operating Reserve Demand Curve[13]



The penalty cost at the first step in the ORDC was set based on historical lost opportunity costs paid to resources on peak days from Jan. 1, 2006, to Nov. 1, 2009, where the ultimate $850/MWh value was selected based on a single event in August 2007.[14] When PJM filed changes to its ORDCs under Reserve Price Formation in March 2019, PJM proposed changing the highest ORDC penalty cost to $2,000/MWh to be consistent with the cost-based energy offer cap. In its response, to the filing, FERC explained its rationale for accepting the proposed change.[15]

> *"The Commission found that, because resources can submit cost-based, price-setting offers as high as $2,000/MWh, resources may face higher, but legitimate, opportunity costs on a more frequent basis going forward. The market price needs to capture these opportunity costs, even if relatively rare, and it will allow emergency and pre-emergency demand response… to set the clearing price for any reserve product."*

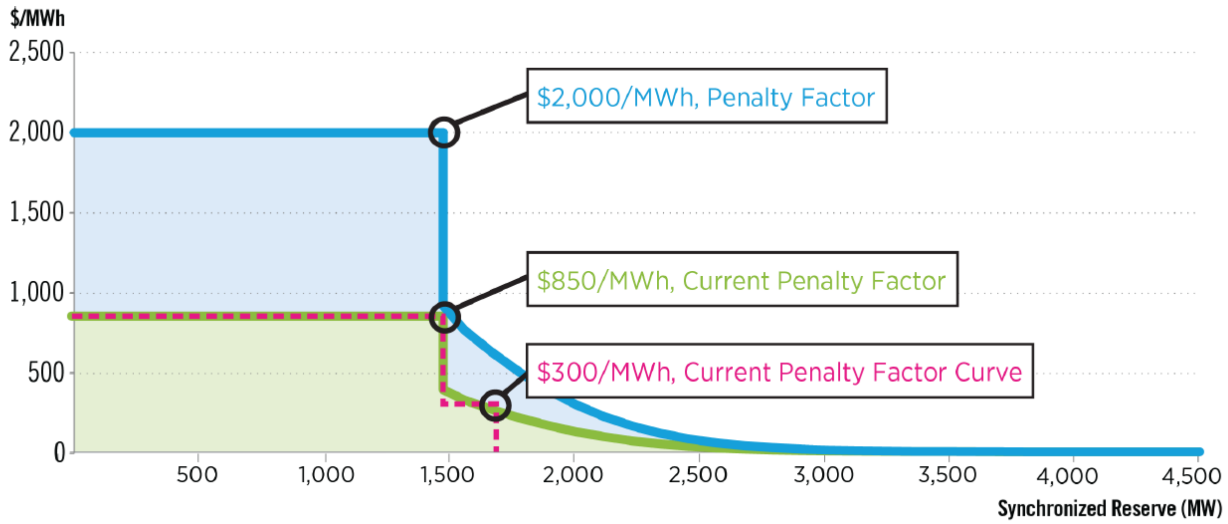
[13] Figure source: PJM Manual 11, Revision 132

[14] PJM Interconnection, LLC, Docket No. ER09-1063, issued April 19, 2012

[15] FERC response to PJM's Price Formation filing, Nov. 3, 2020.

Additionally, PJM proposed a methodology for setting the shape of the ORDCs to reflect the value of reserves above the minimum reliability requirement. Past the minimum reliability requirement (which for Synchronized Reserves (SR) is based on the largest contingency on the system), the benefit of carrying additional reserves is in reducing the probability that PJM would fall below this requirement and end up in a reserve shortage, which could lead to reliability concerns and scarcity prices. The possibility of reserve shortage is primarily driven by forecast uncertainty and generator forced outages. If actual load is higher than was forecasted, more unloaded resources will need to be converted to energy to meet demand, which could lead to a shortage of reserves while dispatchers work to bring more resources online. If wind and solar generation produce less than expected or generation resources experience unplanned outages, this could produce a similar result. As such, PJM developed a demand curve that slopes downward from the minimum reliability requirement and reflects the incremental reduction in value of these services for risk mitigation as more are available on the system. For the 10-minute reserve demand curves, the probability of falling below the minimum reserve requirement is based on the historical 30-minute look-ahead forecast error from the most recent three full calendar years. For the 30-Minute Reserve demand curve, the 60-minute look-ahead forecast error is used.[16] An illustration of this concept is given in **Figure 6**.

Figure 6. Existing and Proposed ORDCs Under Reserve Price Formation[17]



Despite the Commission's original acceptance of the proposed revisions to the ORDCs, this portion of the Reserve Price Formation filing was later remanded, and PJM has continued to use the two-step ORDC shown in Figure 1. As such, PJM was put into the position of implementing only a portion of the comprehensive market design filed in 2019, which resulted in an incomplete market design that continues to exist today.

Challenges To Be Addressed

To be effective, ORDCs must accurately reflect the willingness to pay to mitigate reserve shortage and to avoid loss of load. This ensures that all more cost-effective measures are exhausted before taking more extreme and expensive emergency actions. It also reduces the out-of-market actions that operators need to take to maintain system

[16] Docket No. EL19-58-00, Enhanced Price Formation in Reserve Markets of PJM Interconnection, L.L.C.

[17] Figure source: Operating Reserve Demand Curves (ORDC) for Reserve Price Formation Project

reliability, which can affect prices. Taken together, if ORDCs are not designed to appropriately reflect the actual value that reserve services provide to the system, it can lead to inefficient market outcomes in the short run and inaccurate or insufficient incentive signals in the long run, ultimately compromising system reliability. As stated by FERC on its website related to energy price formation:

> *To the extent that actions taken to avoid reserve deficiencies are not priced appropriately or not priced in a manner consistent with the prices set during a reserve deficiency, the price signals sent when the system is tight will not incent appropriate short- and long-term actions by resources and load.*[18]

PJM's existing ORDCs do not accurately reflect current operational reality, the reliability value that reserves provide, or the actions that PJM would need to take to maintain reliability on the system. As previously mentioned, PJM's current $850/MW penalty factor is based on lost opportunity cost information from a single event more than 17 years ago. Not only is this information outdated, but the metric itself provides an incomplete picture of the cost and value of reserves.

Moving forward, PJM needs to take a holistic approach to its reserve market design, including how reserves are valued, and in consideration of the lessons learned since the Reserve Price Formation filing. In addition to lost opportunity cost, which is a driver for reserve market clearing prices and the costs incurred by resources to provide the reserve service, there are costs that would be incurred to the system in the event of a reserve shortage that should be considered in the discussion of developing an accurate ORDC. PJM Manual 13: Emergency Operations, Section 2.3, Capacity Shortages, describes the procedures that operators follow when in a capacity shortage. These include Pre-Emergency and Emergency Load Management Reductions, declaring a Maximum Generation Emergency, curtailment of non-essential building load, voltage reduction, and finally initiating a Manual Load Dump Action. Many of these actions entail real costs to the system, which are not currently transparent to PJM markets.

Practices in Other ISOs/RTOs

In March 2024, MISO released a position paper proposing ORDC changes and an update to the value of lost load (VOLL) used in its reserve and energy markets.[19] In this paper, MISO details several options and ultimately proposes a VOLL of $10,000/MWh, an increase from the current value of $3,500/MWh. This work was done in part because in its 2023 State of the Market Report,[20] MISO's Independent Market Monitor (IMM) recommended "that MISO improve its shortage pricing by improving its VOLL and the slope of its ORDC." The report goes on to detail the IMM's specific recommendations related to both items:

> *"**Improving the VOLL.** We reviewed the literature and used a model developed by Lawrence Berkeley National Laboratory to estimate an updated VOLL for MISO. This study and others estimate VOLLs that vary substantially by customer class. Using the Berkeley Model and MISO data, we estimated a VOLL of close to $35,000 per MWh.*

[18] Federal Energy Regulatory Commission, Energy Price Formation, last updated on June 17, 2020.

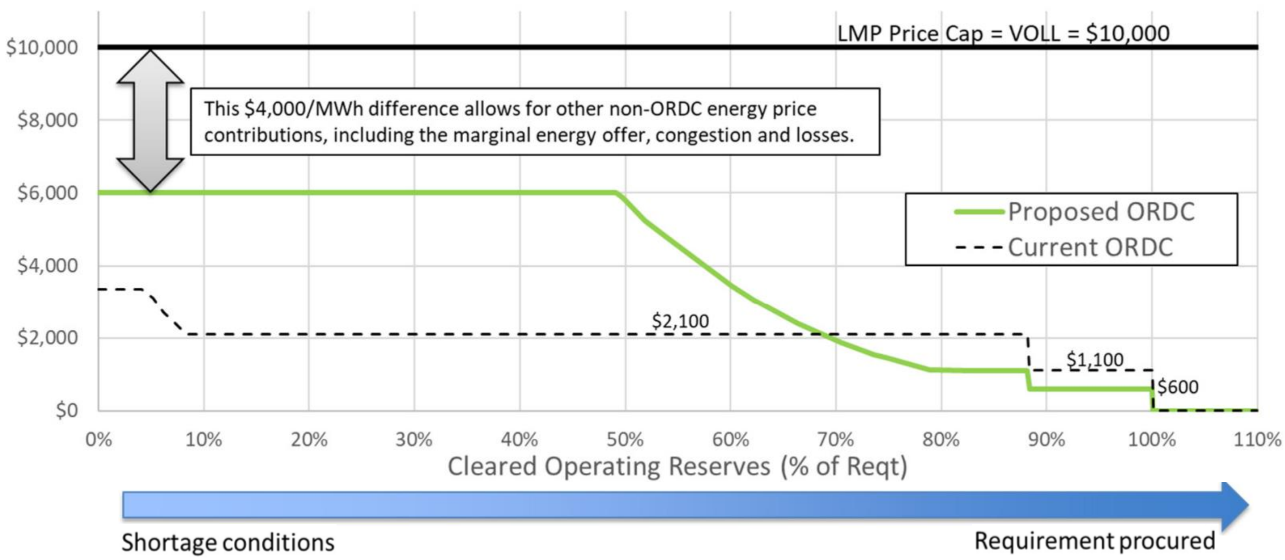
[19] Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve (PDF), MISO, March 2024

[20] 2023 State of the Market Report for the MISO Electricity Markets (PDF), Potomac Economics, June 2024

> *"**Improving the Slope of the ORDC.** The slope of the ORDC is determined by how the probability of losing load changes as the level of operating reserves falls. The probability of losing load depends on the vast combinations of random contingencies and other factors (wind forecast and load forecast errors, and [net-scheduled interchange] uncertainty) that could occur when MISO is short of reserves. We estimated this probability using a Monte Carlo model that simulates these factors."*

MISO ultimately selected a VOLL of $10,000/MWh, deeming that a higher value would be excessive, and this value will be used as a market price cap and for administrative pricing during load-shed events. MISO agreed with its Market Monitor's recommendation to define the ORDC based on the loss of load probability scaled to reflect the cost of shedding firm load and proposes using the $35,000/MWh value recommended by the IMM as the scaling factor. At the same time, MISO will use $6,000/MWh as an ORDC upper limit to "allow prices to appropriately rise toward VOLL as Operating Reserves are depleted." MISO's current and proposed ORDCs are shown in **Figure 7**.

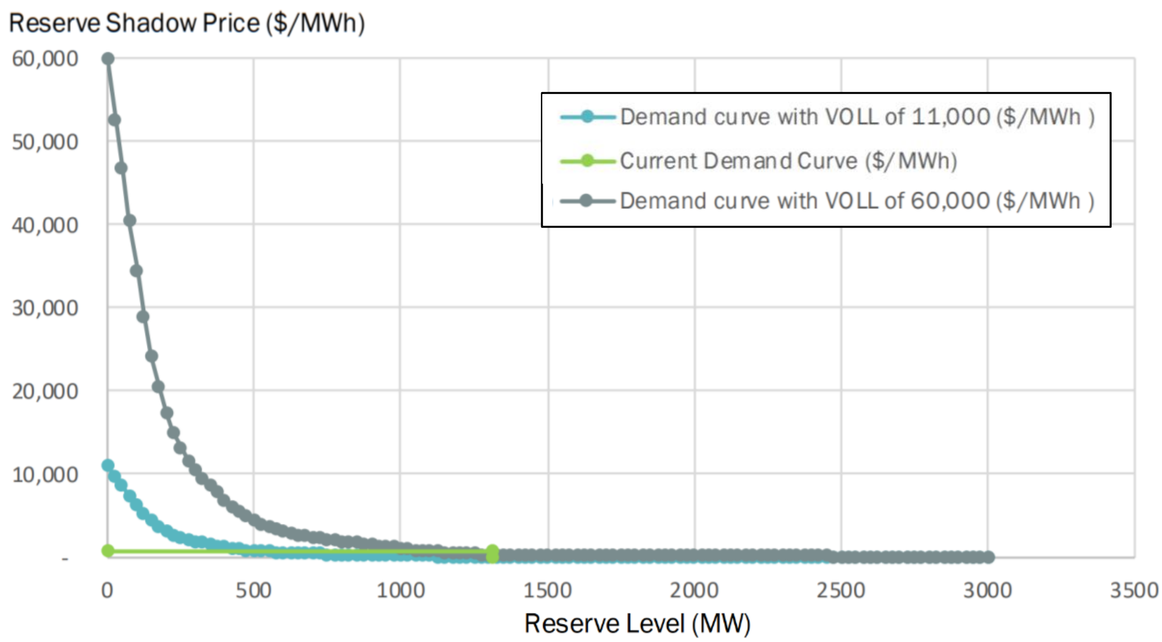
Figure 7. MISO's Current and Proposed Operating Reserve Demand Curves[21]



[21] Figure source: [Scarcity Pricing White Paper: Value of Lost Load and Operating Reserve Demand Curve (PDF)](), March 2024

NYISO also went through a similar process evaluating their ancillary service shortage pricing mechanisms, including analysis of historical shortage events and estimating their VOLL. NYISO also used the Lawrence Berkeley National Laboratory (LBNL) model, which underpinned the VOLL analysis done by MISO's IMM, and calculated that at that time, New York had an average estimated VOLL of $60,000/MWh across all customer types.[22] When using a simpler macroeconomic analytical approach, NYISO estimated its VOLL at $11,000/MWh. NYISO further went on to calculate its loss of load probability (LOLP) based on the approach recommended by Potomac Economics for MISO's 2017 State of the Market Report. NYISO used a Monte Carlo simulation to estimate its LOLP driven by generator forced outage risk, load and intermittent resource forecast error risk, and desired net-interchange error risk. NYISO then generated LOLP curves for its 10- and 30-Minute Reserve products based on these simulation results. **Figure 8** and **Figure 9** show the new ORDCs that NYISO generated based on these VOLL and LOLP results, juxtaposed against its existing demand curves.

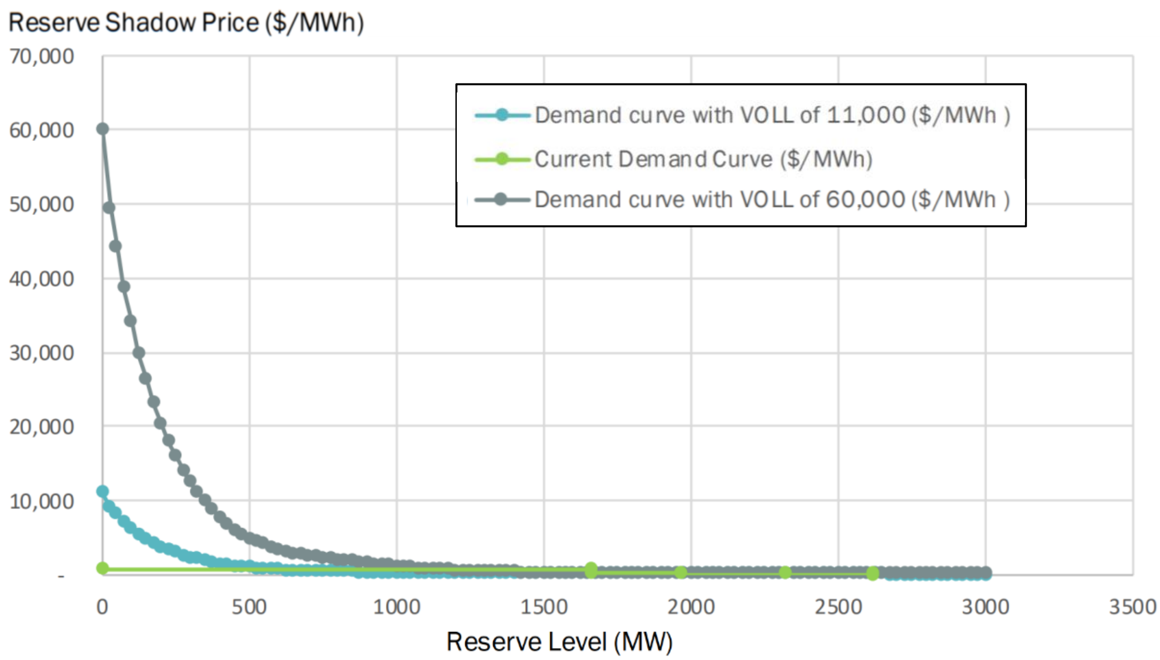
Figure 8. Illustrative VOLL-Based ORDC for New York Control Area (NYCA) 10-Minute Reserves[23]



[22] Ancillary Services Shortage Pricing (PDF), NYISO, December 2019

[23] Figure source: Ancillary Services Shortage Pricing (PDF), NYISO, December 2019

Figure 9. Illustrative VOLL-Based ORDC for New York Control Area (NYCA) 30-Minute Reserves[24]



The Impact Of ORDCs In Market Clearing Outcomes

ORDCs are used in both PJM's commitment and dispatch market engines to determine above what level PJM will not incur additional cost to make reserves available. In the case of PJM's commitment engine, this will dictate which resources are committed to the system for the purpose of providing or making available reserve services. If the ORDC penalty factors are lower than the incremental costs that would need to be incurred to commit a resource (e.g., resource start-up and no-load costs), then the optimization will go short reserves rather than commit that resource. In the dispatch engine, the ORDC penalty factors limit the costs that the system will incur to redispatch to make reserve services available. Today, those costs are based on the lost opportunity costs that resources would incur to provide reserves in lieu of providing energy. If the ORDC penalty factors are lower than the incremental costs that would need to be incurred to back a resource down to make reserves available, the optimization will once again go short reserves rather than redispatch that resource. Below are two very simple examples walking through these market engine clearing outcomes to illustrate these two points.

The following assumptions apply to both examples presented:

- Only the RTO-level SR requirement is considered for simplicity. No other reserve product is considered.
- In the commitment example, only one interval is considered for simplicity. The example addresses the load requirement as the first priority followed by meeting the reserve requirement with remaining resource capability (as available).
- A single step ORDC is considered at the penalty factor specified for each scenario.

[24] Figure source: Ancillary Services Shortage Pricing (PDF), NYISO, December 2019

- Resources SR offer prices are $0, consistent with the SR offer cap today.

Example 1: Commitment

The inputs for the example are given in **Table 8** and **Table 9**.

Table 8. System level requirements

Load (MW)	599
SR Requirement (MW)	2

Table 9. Unit parameters and offers

	Gen1	Gen2
EcoMin (MW)	0	0
EcoMax (MW)	600	600
Energy Offer ($/MWh)	50	60
Start-up cost ($)	0	851
No-load cost ($/hr)	0	0

The market clearing engine outcomes for running this commitment problem with first a penalty factor of $850 and then increasing that penalty factor to $852 are given below. Note that while the optimization engine performs the co-optimization of energy and reserve simultaneously, it is presented below separately for the purpose of explaining the results.

Solution Using a SR Penalty Factor of $850/MW

The cost to start each resource and run at its economic minimum is based on each resource's offer and given in **Table 10**.

Table 10. The costs incurred to commit each resource.

	Commitment Costs + Cost to Run at EcoMin
Gen1	$0
Gen2	$851

To meet the energy requirement of 599 MW, either Gen1 or Gen2 can meet the load with the following production costs:

Gen1 Cost = Start-up cost + No-load Cost + Incremental energy cost

*= 0 + 0 + (599*50) = $29,950*

Gen2 Cost = Start-up cost + No-load Cost + Incremental energy cost

*= 851 + 0 + (599*60) = $36,791*

As Gen1 can meet the full load requirement at least cost, Gen1 would be committed for energy and provide 599 MW.

Co-optimization of Energy and Reserve

Gen1's unloaded online reserve capability of 1 MW will be counted toward fulfilling the 2 MW SR requirement. This incurs no additional cost to the system. However, there is no additional unloaded online reserve capability available because Gen2 is offline, meaning that there is still 1 MW of SR needed to meet the SR requirement. This 1 MW either needs to come from committing Gen2 or from a fictitious resource that costs $850/MW, the SR penalty factor. The cost for each of these options is given below.

Option 1:

If Gen2 is committed for energy at 0 MW it would have sufficient unloaded capability to meet the remaining 1 MW SR requirement. The total cost to get this 1 MW of SR from Gen2 would be:

*Start-up cost + No-load cost + Incremental energy cost = (851 + 0 + 0*60) = $851*

Option 2:

If the fictitious resource with a penalty factor of $850 provides the one additional megawatt to meet the SR requirement then the cost would be:

*Penalty factor * SR shortage megawatts = 850*1 = $850*

In this case, it is therefore more economical to go into shortage for 1 MW of SR rather than commit Gen2 to meet the SR requirement.

System Energy Price

Gen1 is committed and dispatched to 599 MW to meet the load. To supply the next megawatt of energy, Gen1, as the marginal resource, needs to provide the additional megawatt at a cost of $50. However, that would reduce 1 MW of SR contribution to meet the SR requirement and that would have to come from fictitious resource at the cost of $850. Therefore, the next 1 MW of energy would increase the overall production cost by $900. ($50 for the increase in energy cost for Gen1 to meet the 1 MW of additional demand and $850 to meet the SR requirement at the penalty factor. Therefore, the shadow price of the power balance constraint is $900. This sets an energy-clearing price of $900/MWh.

Reserve Clearing Price

If the reserve requirement is increased by 1 MW, it would come from the fictitious resource for $850 as that is the most economical option to meet the requirement. Hence, the shadow price of SR requirement would be $850/MWh.

Solution Using a SR Penalty Factor of $852/MW

The cost to start each resource and run at its economic minimum would remain the same as seen above with the SR penalty factor of $850**.** The energy requirement would also be met in the same way as previously described.

Co-optimization of Energy and Reserve

To meet the 2 MW SR reserve requirement, Gen1's unloaded online reserve capability of 1 MW will be counted toward fulfilling the SR requirement. This incurs no additional cost to the system. However, there is no additional unloaded online reserve capability available because Gen2 is offline, meaning that there is still 1 MW of SR needed to meet the SR requirement. This 1 MW either needs to come from committing Gen2 or from the fictitious resource that costs $852/MW, the SR penalty factor. The cost of each option is detailed below.

Option 1:

If Gen2 is committed for energy at 0 MW it would have sufficient unloaded capability to meet the remaining 1 MW SR requirement. The total cost to get this 1 MW of SR from Gen 2 would be:

*Start-up cost + No-load cost + Incremental energy cost = (851 + 0 + 0*60) = $851*

Option 2:

If the fictitious resource with the penalty factor of $852 provides the one additional megawatt to meet the SR requirement then the cost would be:

*Penalty factor * SR shortage megawatts = 852*1 = $852*

In this case, it is therefore more economical to commit Gen 2 to meet the reserve requirement rather than violating the SR requirement at a penalty cost of $852/MW.

System Energy Price

Gen1 is committed and dispatched to 599 MW to meet the load. To supply the next megawatt of energy, Gen1, as the marginal resource, needs to provide the additional megawatt at a cost of $50. However, that would reduce its 1 MW of SR contribution to meet the SR requirement. That additional megawatt would then come from Gen2 as it is now online and has unloaded capability at no cost. Hence, the next 1 MW of energy would increase the overall cost by $50. Therefore, the shadow price of power balance constraint is $50. This sets an energy-clearing price of $50/MWh.

Reserve Clearing Price

If the reserve requirement is increased by 1 MW, it would come from Gen2's unloaded capability as that is the most economical option to meet the requirement. Hence, the shadow price of SR requirement would be $0.

Error! Reference source not found. provides a summary of these commitment example results for both the $850/MW and $852/MW penalty factors.

Table 11. Summary of Example 1 results.

$850 Penalty Factor				$852 Penalty Factor			
System Energy Price ($)			**900**	**System Energy Price ($)**			**50**
SR Clearing Price ($)			**850**	**SR Clearing Price ($)**			**0**
SR Deficit (MW)			**1**	**SR Deficit (MW)**			**0**
	Commit Status	**Energy Dispatch (MW)**	**SR Assignment (MW)**		**Commit Status**	**Energy Dispatch (MW)**	**SR Assignment (MW)**
Gen1	**online**	**599**	**1**	**Gen1**	**online**	**599**	**1**
Gen2	***offline***	**0**	**0**	**Gen2**	***offline***	**0**	**1**

Example 2: Dispatch

The inputs for the example are given in **Table 12** and **Table 13**.

Table 12. System level requirements

Load (MW)	600
SR Requirement (MW)	20

Table 13. Unit parameters and offers

	Gen1	Gen2	Gen3
EcoMin (MW)	0	0	0
EcoMax (MW)	200	200	300
Energy Offer ($/MWh)	1000	20	10
Initial Operating Point (MW)	100	200	300
Ramp Rate (MW/Min)	1	5	5

The optimization engine performs the co-optimization of energy and reserves simultaneously. However, for the purpose of illustrating the market clearing engine outcomes, the results are broken out in the explanations below.

Solution Using a SR Penalty Factor of $850/MW

The energy dispatchable range for each unit, which is based on initial MW, energy time horizon, ramp rate, and a resource's economic limits is determined as described below.

*Lowest energy dispatch point = Maximum ([Initial MW – ramp rate*60], EcoMin)*

*Highest energy dispatch point = Minimum ([Initial MW + ramp rate*60], EcoMax)*

The unit-specific dispatchable range based on resource input parameters are given in **Table 14**.

Table 14. Resource dispatchable ranges.

	Energy Dispatchable Range
Gen1	40-160 MW
Gen2	0-200 MW
Gen3	0-300 MW

To meet the load requirement of 600 MW, the least cost resource, Gen3, provides its maximum megawatt capability of 300 MW of energy. The next economic resource is Gen2, which will provide its maximum megawatt capability of 200 MW of energy towards meeting the requirement. The remaining 100 MW of load to be served (600 MW – 300 MW – 200 MW = 100 MW) will be provided by Gen1. **Table 15** provides a summary of these dispatch results.

Table 15. Resource dispatch to meet load.

	Energy MW
Gen1	100
Gen2	200
Gen3	300

Co-optimization of Energy and Reserve

To meet the 20 MW SR reserve requirement, Gen1's unloaded online reserve capability of 10 MW, based on its ramp capability, will be counted towards fulfilling the SR requirement. Because this is available unloaded capability, this incurs no additional cost. However, there is no additional unloaded online reserve capability available because Gen2 and Gen3 are fully dispatched to their EcoMax values to meet load.

To procure the needed SR, there are three options available as described below.

Option 1:

Reduce the energy output from Gen2 to make room to provide the additional 10 MW of needed SR to meet the SR requirement. However, to maintain power balance, Gen1 would have to increase its energy output by 10 MW. The total cost to re-dispatch under this option is therefore:

*Increase in energy cost for Gen1 – Decrease in energy cost from Gen2 = 1000*10 – 10*20 = $9,800*

Option 2:

Reduce the energy output from Gen3 to make room to provide the additional 10 MW of needed SR to meet the SR requirement. However, to maintain power balance, Gen1 would have to increase its energy output by 10 MW. The total cost to re-dispatch under this option is therefore:

*Increase in energy cost for Gen1 – Decrease in energy cost from Gen2 = 1000*10 – 10*10 = $9,900*

Option 3:

Without any energy re-dispatch among resources, the needed 10 MW of SR would be provided by a fictitious resource at the penalty factor of $850. The total cost for meeting the remaining 10 MW of the SR requirement would therefore be:

*Penalty factor * SR shortage megawatts = 850*10 = $8,500*

Out of all three options available to meet the SR requirement, option 3 is the most economical, and so the optimization engine would not redispatch the system to provide the additional 10 MW of reserves and allow the system to go into shortage.

Table 16 summarizes the energy dispatch points and SR assignments resulting from the co-optimized energy and reserve solution with a $850/MW penalty factor.

Table 16. Summary of resource energy and SR assignments given a $850/MW penalty factor

	Energy MW	Sync Reserve MW
Gen1	100	10
Gen2	200	0
Gen3	300	0

System Energy Price

Gen1, Gen2, and Gen3 are dispatched to 100 MW, 200 MW, and 300 MW respectively. To suppy the next megawatt of energy, Gen1 needs to provide an additional megawatt at a cost of $1,000 because Gen2 and Gen3 are dispatched at their maximum capability. Therefore, the shadow price of power balance constraint is $1000. This sets an energy-clearing price of $1,000/MWh.

Reserve Clearing Price

If the SR requirement is increased by 1 MW, it would come from a fictitious resource at a cost of $850/MW. Therefore, the shadow price of the SR requirement would be $850/MWh and the reserve clearing price would also be $850/MWh.

Solution Using a SR Penalty Factor of $1000/MW

The energy dispatchable range for each resource and energy dispatch solution to meet load would be the same as explained above for a penalty factor of $850.

Co-optimization of Energy and Reserve

To meet the 20 MW SR reserve requirement, Gen1's unloaded online reserve capability of 10 MW will be counted towards fulfilling the SR requirement. However, there is no additional unloaded online reserve capability available because Gen2 and Gen3 are being dispatched to their EcoMax values to meet the load requirement.

To procure the needed additional 10 MW of SR, there are three options available as described below.

Option 1:

Reduce the energy output from Gen2 to make room to provide the additional 10 MW of needed SR to meet the SR requirement. However, to maintain power balance, Gen1 would have to increase its energy output by 10 MW. The total cost to re-dispatch under this option is therefore:

*Increase in energy cost for Gen1 – Decrease in energy cost from Gen2 = 1000*10 – 10*20 = $9,800*

Option 2:

Reduce the energy output from Gen3 to make room to provide the additional 10 MW of needed SR to meet the SR requirement. However, to maintain power balance, Gen1 would have to increase its energy output by 10 MW. The total cost to re-dispatch under this option is therefore:

*Increase in energy cost for Gen1 – Decrease in energy cost from Gen2 = 1000*10 – 10*10 = $9,900*

Option 3:

Without any energy re-dispatch among resources, the needed 10 MW of SR would be provided by a fictitious resource at the penalty factor of $1,000/MW. The total cost for meeting the remaining 10 MW of the SR requirement would therefore be:

*Penalty factor * SR shortage megawatts = 1000*10 = $10,000*

Out of all three options available to meet the SR requirement, option 1 is the most economical, which is to reduce the energy of Gen2 such that it has available headroom to provide the needed SR. As a result, Gen2 will provide 10 MW of SR towards fulfilling the SR requirement along with Gen1 which is providing its 10 MW of unloaded capability.

Table 17 summarizes the energy dispatch points and SR assignments resulting from the co-optimized energy and reserve solution with a $1000/MW penalty factor.

Table 17. Summary of resource energy and SR assignments given a $1000/MW penalty factor

	Energy MW	Sync Reserve MW
Gen1	110	10
Gen2	190	10
Gen3	300	0

System Energy Price

Gen1, Gen2, and Gen3 are dispatched to 110 MW, 190 MW, and 300 MW respectively. To meet the next megawatt of energy demand, Gen1 needs to provide the additional megawatt at a cost of $1,000 since that is most economical. Therefore, the shadow price of power balance constraint is $1000, and this sets an energy-clearing price of $1,000/MWh.

Reserve Clearing Price

If the SR requirement is increased by 1 MW, that requirement would be met by reducing 1 MW of energy output from Gen2 and increasing the energy output from Gen1 by 1 MW. This cost of these actions would be as follows:

*Increase in cost of Gen1 – Decrease in cost of Gen2 = 1000*1 – 1*20 = $980*

Therefore, the shadow price of the SR requirement would be $980 and so the reserve clearing price would also be $980.

Table 18 provides a summary of these commitment example results for both the $850/MW and $1000/MW penalty factors.

Table 18. Summary of Example 2 results.

$850 Penalty Factor			$1000 Penalty Factor		
System Energy Price ($)		1000	System Energy Price ($)		1000
SR Clearing Price ($)		850	SR Clearing Price ($)		980
SR Deficit (MW)		10	SR Deficit (MW)		0
	Energy Dispatch (MW)	SR Assignment (MW)		Energy Dispatch (MW)	SR Assignment (MW)
Gen1	100	10	Gen1	110	10
Gen2	200	0	Gen2	190	10
Gen3	300	0	Gen3	300	0

Analysis Of A Recent Reserve Shortage Event

Most instances of reserve shortage that have occurred since the Reserve Price Formation changes were implemented were during Winter Storm Elliot in December 2022. However, PJM does experience instances of reserve shortage outside of these more major events. For example, in February 2025, PJM had reserve shortage events on two days, February 5 and February 11. Both were relatively short events, the one on February 5th lasting two intervals, and the one on February 11 lasting a single interval. PJM ran a simple counterfactual scenario for one of the two intervals on February to evaluate whether more reserves were available on the system that could have alleviated the SR shortage in the RTO if the penalty factor had been increased. **Table 19** provides the SR deficit and SR market clearing price (MCP) that occurred during this interval with the $850 as well as the SR deficit and SR MCP that would have occurred if the penalty factor for the first step of the ORDC had been increased to $1,500.

Table 19. Results of an analysis of a shortage interval in RTO on February 5, 2025, 10:15.

First Step Penalty Factor	SR Deficit (RTO)	SR MCP (RTO)	Deficit type
$850 *(status quo)*	258 MW	$850	Minimum reliability requirement (i.e., first step)
$1,500	190 MW	$1,361	Extended reserve requirement (i.e., second step)

During this interval, PJM had a SR shortage of 258 MW in the RTO, which included a 68 MW deficit below the first step of the ORDC at the $850/MW penalty factor and a 190 MW deficit below the second step of the ORDC at the $300/MW penalty factor. Increasing the $850/MW penalty factor to $1,500/MW cleared the shortage experienced at the minimum reliability requirement but left the willingness to pay at the extended reserve requirement unchanged, resulting in a 190 MW deficit of the extended reserve requirement at the second step of the ORDC. These results demonstrate that during this interval, reserves were available on the system at a cost above $850/MW, which suggests that PJM's current ORDC penalty factors are not high enough to reflect the lost opportunity costs that resources can reasonably be expected to incur to provide reserve services.

PJM's Preliminary Design Perspectives

In considering how to update PJM's ORDCs to better align with current operational reality and system reliability needs, there are several questions that need to be explored including how to accurately represent the willingness to pay for reserve services to avoid loss of load, what ORDC shape best reflects the value of reserve services at different levels, and how PJM's ORDCs for different reserve products fit together to form a cohesive market design.

Willingness to Pay for Reserves

An effective ORDC should ensure that 1) all more cost-effective actions are taken prior to engaging more expensive emergency procedures up to and including Manual Load Dump and 2) that those costs are made transparent to the market. ORDC penalty factors must therefore be high enough to trigger these remedial actions rather than allowing the system to go short reserves unnecessarily.

Today, as discussed in the analysis of a recent shortage event, this is not the case even when considering the relatively routine lost opportunity costs incurred by resources to provide reserves in lieu of providing energy. As a shortage condition escalates, and in particular in the case of a SR shortage, the ultimate cost is manual load shed. This is the final emergency operational action detailed in PJM's Manual 13: Emergency Operations, Section 2.3 Capacity Shortages, and will be taken as a last resort to protect the system from cascading outages.

The maximum willingness to pay for reserves where the cost of under-procurement is shedding load should be considered in the context of the value of lost load. While it may ultimately be impossible to arrive at a single, unequivocal number that accurately represents PJM's VOLL, the industry has invested significant time and effort in estimating the costs of interruptions to electricity service, including using macroeconomic modeling, such as calculating gross domestic product (GDP) to load ratios, post-event analysis following blackouts, customer surveys, and market behavior observations.[25]

LBNL conducted a meta-analysis of over 100,000 customer surveys and then developed a regression model that drives their online Interruption Cost Estimate (ICE) Calculator. This methodology may be the most broadly accepted model for estimating VOLL and was used to inform the MISO and NYISO shortage pricing analyses as previously described. Conducting a similar analysis for PJM's footprint using this model yields a VOLL of $68,000 in 2023 dollars.[26] On the other hand, doing a simple GDP to load ratio calculation, as was done by both NYISO and London Economics when estimating ERCOT's VOLL,[27] yields a value of roughly $7,000 in 2023 dollars based on 2022 data.[28] Additionally, there is broad consensus that different customer classes have different costs for interruption of service. LBNL's calculator estimates the cost of electricity service interruption for PJM's residential customers closer to $6,000/MWh, much lower than the system-wide weighted average of $68,000/MWh. Given that different consumers may have a very different willingness to pay to avoid service interruptions, the most market efficient solution would be to remove any frictions that currently exist to allow consumers to express this willingness to pay directly through participation in Price Responsive Demand or Demand Response programs and to allow prices to rise to reflect the higher willingness to pay of customers for whom service interruption is extremely costly.

While PJM is unlikely to arrive at a single and unequivocal VOLL number, understanding the credible range of values may provide a helpful backdrop in discussing a willingness to pay for reserves. Additionally, there are practical market efficiency questions that can inform the discussion. For instance, there are costs that are routinely incurred to provide these services, such as resource lost opportunity and commitment costs, as well as the costs of emergency actions that system operators may need to take to maintain system reliability in the event a Capacity Shortage event. Given that those actions entail real costs, allowing reserve prices to rise to approach these costs would ensure that if reserves can be procured at less expense, the market optimization engines will recognize that either committing resources or re-dispatching the system is actually the cost minimizing option rather than allowing the system to go into reserve shortage.

ORDCs for Separate Products

Each reserve product has its own ORDC, which should reflect the procurement quantities and willingness to pay for that essential reliability service. The willingness to pay for a reserve product is based on the "quality" of that product. In other words, the willingness to pay for a lower quality product will likely be lower than for a higher quality product. Therefore, procuring one type of reserve can mitigate the likelihood of going short another type of reserve. For example, this has been demonstrated in the market designs of other ISOs where uncertainty reserves help mitigate contingency reserve shortage. PJM believes it will be important to evaluate and reform its existing ORDCs for Synchronized, Primary and 30-Minute Reserves to ensure that the reliability value of these services is appropriately

[25] The quest to quantify the value of lost load: A critical review of the economics of power outages, Will Gorman, October 2022

[26] More detail on the approach used to conduct this analysis is provided in the Appendix.

[27] Estimating the Value of Lost Load (PDF), prepared for ERCOT by London Economics, June 17, 2013

[28] More detail on the approach used to conduct this analysis is provided in the Appendix.

captured for each in the context of the broader reserve reforms being discussed. Additional products will require new ORDCs and they will need to fit appropriately within this framework.

Additional Market Reforms

In addition to updates to PJM's ORDCs as discussed above, there are other existing market constructs that may need to be discussed to ensure an efficient and coherent market design. Some of these items reflect areas where PJM's current reserve procurement, deployment, performance incentives and compensation do not align with operational practice or do not sufficiently support reliable operations. Other items may need to be revisited as the broader reforms are undertaken for consistency across PJM's reserve markets and to support reserve certainty into the future. These items are outlined briefly in **Table 20**, and will be expanded on as discussions progress in the RCSTF.

Table 20. Summary of potential additional market reforms needed to support the long-term RCSTF scope.

<table>
<tr><th colspan="2">Performance Obligation, Evaluation and Consequences of Non-Performance for Resources with a Reserve Assignment</th></tr>
<tr><td>Why might reforms be necessary?
Consequences of non-performance today do not always reflect the impact to the system or how reserve products are used for reliability.
Consequences of non-performance may not be structured to sufficiently promote reserve certainty.
As PJM relies more heavily on reserves to manage uncertainty, it is critical that resources follow PJM dispatch instructions.</td><td>Possible design discussions
New settlement impacts when reserve resources fail to perform
Reforms to performance evaluation rules
Changes or clarification to reserve performance obligation and resource qualification
New incentives to follow PJM dispatch, including reforms to deviation charges</td></tr>
<tr><td colspan="2">Open Questions
Should performance evaluation and consequences for non-performance for following dispatch be different for resources with and without a reserve assignment?
Would performance-based reserve qualification increase reserve certainty?</td></tr>
<tr><th colspan="2">Resource Offers for Providing Reserve Services</th></tr>
<tr><td>Why might reforms be necessary?
Resources may not currently be able to reflect avoidable costs, such as fuel arrangements or</td><td>Possible design discussions
New offer rules allowing resources to reflect avoidable costs into reserve offers</td></tr>
</table>

charging, for reserve services into their reserve offers. These costs may therefore be unrecoverable through PJM's markets.	
Open Questions • In addition to costs, are there other structural reforms needed to reserve offers to reflect resource capability, such as reserve-specific parameters?	

PJM RCSTF Long-Term Scope Package

To be populated in future updates

Appendix

Analysis Details

VOLL Calculation: Gross Domestic Product (GDP) to Load Ratio

$$VOLL = \sum_{k=1}^{n} \frac{GDP_i}{Load_i} C_i$$

Where:

- GDP: State annual GDP (2022$)
- Load: State annual load (MWh)
- C: Percentage of State contribution to PJM's overall load

Table 21. 2022 Data Used in GDP to Load VOLL Calculation

STATE	GDP (Millions of $)[29]	Annual Load (Million kWh)[30]	Percentage of PJM Load[31]
DC	165,061	10,241	1.2%
DE	90,208	11,539	1.6%
IL	1,025,667	135,872	11.9%
IN	470,324	100,044	2.8%
KY	258,981	75,338	2.9%
MD	480,113	59,683	8.1%
MI	622,563	100,639	0.6%
NC	715,968	139,207	0.6%
NJ	754,948	74,443	9.8%
OH	825,990	149,500	19.8%
PA	911,813	145,045	19.4%
TN	485,658	102,112	0.2%
VA	663,106	132,265	16.6%
WV	97,417	32,986	4.6%
VOLL ***~ $6,500 (2022$)*** *or* ***~$7,000 (2023$)***			

VOLL Calculation: Lawrence Berkeley National Laboratory (LBNL) ICE Calculator

The LBNL ICE Calculator[32] was used to estimate the interruption costs of a single average hour, using the breakdown of residential and non-residential load by state from 2022,[33] and weighted by each state's contribution to

[29] Source: Bureau of Economic Analysis

[30] Source: U.S. Energy Information Administration

[31] Source: Monitoring Analytics

[32] Ice Calculator

[33] Sources: EIA State Profiles , EIA Data Browser

PJM's total load in the same year.[34] Nonresidential load was assumed to be 25% small commercial and industrial (C&I) customers, and 75% medium and large C&I customers.

	Residential	Small C&I	Medium and Large C&I	Weighted Total
ICE Calculator Results:	$5,900	$220,000	$67,000	**$68,000**
**All values updated to 2023$ from 2016$ provided by ICE Calculator.*				

[34] Source: Monitoring Analytics